NUREG-1831

Safety Evaluation Report
Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2

Docket Nos. 50-315 and 50-316

Indiana Michigan Power Company

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

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Indiana Michigan Power Company

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated October 31, 2003, Indiana Michigan Power Company (the applicant) submitted the LRA for CNP in accordance with Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54 or the Rule). The applicant is requesting renewal of the operating license for CNP Unit 1 (License No. DRP-58) and CNP Unit 2 (License No. DRP-74) for a period of 20 years beyond the current license expirations of midnight, October 25, 2014 and December 23, 2017, respectively.

The CNP is located along the eastern shore of Lake Michigan in Lake Charter Township, Berrien County, Michigan; approximately 11 miles south southwest of Benton Harbor, Michigan. The nearest town is Bridgman, Michigan, which is approximately 2 miles south of the plant site. Each unit employs a pressurized water reactor (PWR) nuclear steam supply system (NSSS) furnished by Westinghouse Electric Corporation. The Unit 1 reactor is licensed for a power output of 3304 megawatts-thermal (MWt), and the Unit 2 reactor is licensed for a power output of 3468 MWt. The approximate net electrical outputs of Unit 1 and Unit 2 are 1080 megawatts-electric (MWe) and 1155 MWe, respectively.

The staff reviewed the CNP 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. The staff's conclusion of its review of the CNP LRA can be found in Section 6 of this SER.

The NRC CNP license renewal project manager is Mr. Jonathan Rowley. Mr. Rowley may be reached at 301-415-4053. Commenters should address written correspondence to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

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ABBREVIATIONS

ac	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor steel reinforced
ADAMS	Agencywide Documents Access and Management System
AEC	Atomic Energy Commission
AEP	American Electric Power
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
AMRR	aging management review reports
ANSI	American National Standards Institute
APCSB	auxiliary and power conversion systems branch
ARDM	age related degradation mechanism
AS	auxiliary steam
ASME	American Society of Mechanical Engineers
AST	alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AVB	antivibration bar
BD	blowdown
BMI	bottom-mounted instrumentation
B&PV	Boiler and Pressure Vessel
BTP	branch technical position
B&W	Babcock and Wilcox Co.
BWR	boiling-water reactor
CASS	cast austenitic stainless steel
CC	concrete containments
CCP	centrifugal charging pump
CCW	component cooling water
CE	Combustion Engineering
CEQ	containment equalization / hydrogen skimmer system
CF	chemical feed
CFR	Code of Federal Regulations
CI	confirmatory item
CLB	current licensing basis
CMAA	Crane Manufactures Association of America
CNP	Donald C. Cook Nuclear Plant
CO2	carbon dioxide
CR	condition report
CRDM	control rod drive mechanism
CST	condensate storage tank

CUF	cumulative usage factor
CTRL	control air
CVC	chemical and volume control system
CW	circulating water
DBD	design basis document
DBE	design basis event
DE	Division of Engineering
DEMIN	demineralized water
DEQ	Department of Environmental Quality
DRAIN	process drains – miscellaneous drain tank
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full power year
EPRI	Electric Power Research Institute
EQ	environmental qualification
EQDB	equipment qualification database
ER	Environmental Report
ES	engineering services
ESF	engineered safety features
ESFAS	engineered safety feature actuation system
ESRR	Expanded System Readiness Review
ESW	essential service water
FAC	flow-accelerated corrosion
FDB	facility database
FERC	Federal Energy Regulatory Commission
FIV	flow-induced vibration
FMP	fatigue monitoring program
FP	fire protection
FPPM	Fire Protection Program Manual
FRV	feedwater regulating valve
FSAR	final safety analysis report
FW	feedwater
GALL	generic aging lessons learned
GDC	general design criterion
GEIS	generic environmental impact statement
GL	generic letter
GSI	generic safety issue
HE	heat exchanger
HELB	high energy line break
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning

IASCC	irradiation-assisted stress corrosion cracking
I&C	instrumentation and controls
ICE	ice condenser
ICLF	ice condenser lattice frames
IGA	intergranular attack
IGSCC	intergranular stress corrosion cracking
I&M	Indiana Michigan Power Company
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
ISSR	individual system / structure reports
ITG	issues task group
ksi	kips per square inch
LAS	low alloy steel
LBB	leak before break
LER	licensee event report
LOCA	loss-of-coolant accident
LRA	license renewal application
LRP-MAMR	License Renewal Project Mechanical Aging Management Report
LRP-PG	License Renewal Project Guideline
LRP-TR	Topical Report for License Renewal Scoping
LTOPS	low temperature overpressure protection system
LTW	Lake Charter Township water
M	margin value to account for uncertainties
MATL	material/equipment handling
MDAFP	motor-driven auxiliary feedwater pumps
MDEQ	Michigan Department of Environmental Quality
MeV	million electron volts
MIC	microbiologically induced or influenced corrosion
MRP	Materials Reliability Project
MSLB	main steam line break
MSS	Manufacturers Standardization Society
MT	main turbine
MWe	megawatt-electric
MWt	megawatt-thermal
n/cm^2	neutron per square centimeter
N2	reactor nitrogen system
NDE	nondestructive examination
NDT	nil ductility transition
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act of 1969
NESW	nonessential service water system
NF	nuclear fuel

NFPA	National Fire Protection Association
NPS	nominal pipe size
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NS	nuclear sampling
NSSS	nuclear steam supply system
NUMARC	Nuclear Management and Resource Council
NUREG	NRC technical rapport designation
OBE	operating-basis earthquake
ODSCC	outer diameter stress corrosion cracking
OFPW	offsite power
PA	plant air
PACHMS	post-accident containment hydrogen monitoring system
PASS	post-accident sampling system
P&ID	piping and instrumentation diagram
PORV	power operated relief valve
ppb	parts per billion
ppm	parts per million
PRT	pressurizer relief tank
PSDC	plant-specific design criteria
PTS	pressurized thermal shock
P-T	pressure-temperature
PW	primary water
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
QAPD	Quality assurance Program description
RAI	request for additional information
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RIS	NRC Regulatory Issue Summary
RLEP	NRR License Renewal and Environmental Impacts Program Branch
RPV	reactor pressure vessel
RMS	radiation monitoring system
RT	reference temperature
RT_{PTS}	reference temperature for pressurized thermal shock
RT_{NDT}	reference nil ductility transition temperature
RV	reactor vessel
RVH	reactor vessel head
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RVLIS	reactor vessel level indication system

RVSP	Reactor Vessel Surveillance Program
RWD	*radioactive waste disposal*
RWST	refueling water storage tank
SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking
SCRN	screen wash
SCW	provide source of cooling
SD	station drainage
SE	safety evaluation
SER	safety evaluation report
SFP	spent fuel pool
SG	steam generator
SGBD	steam generator blowdown
SI	safety injection
SMP	Structures Monitoring Program
SOC	Statements of Consideration
SRP-LR	Standard Review Plan - License Renewal
SRXB	NRR Reactor Systems Branch
SSC	structure system and component
SSD	safe shutdown
SW	service water
TDAFP	turbine-driven AFW pump
TDR	time domain reflectometry
TLAA	time-limited aging analysis
UFSAR	*updated final safety analysis report*
USAS	United States of America Standard
USE	upper shelf energy
VA	auxiliary building ventilation system
VAB	auxiliary building ventilation
VCONT	containment ventilation
VCRAC	control room ventilation system
VEDG	emergency diesel generator ventilation system
VES	engineered safety features ventilation
VHP	vessel head penetration
VMISC	miscellaneous ventilation
VSFP	spent fuel pool ventilation
VSWGR	switchgear ventilation system
VT	visual test
WCAP	Westinghouse Commercial Atomic Power
WOG	Westinghouse Owner's Group
XLPE	cross-linked polyethylene

1. INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal for the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, as filed by the Indiana Michigan Power Company (I&M or the applicant). By letter dated October 31, 2003, I&M submitted its application to the U.S. Nuclear Regulatory Commission (NRC or the staff) for renewal of the CNP operating license for an additional 20 years. The NRC staff (the staff) prepared this report, which summarizes the results of the staff's safety review of the renewal application for compliance with the requirements of Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54). The NRC license renewal project manager for the CNP license renewal review is Mr. Jonathan Rowley. Mr. Rowley may be contacted by calling 301-415-4053, emailing JGR@nrc.gov, or writing to the License Renewal and Environmental Impacts Program, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC, 20555-0001.

In its October 31, 2003, submittal letter, the applicant requested renewal of the operating license issued under Section 104b of the Atomic Energy Act of 1954, as amended (Facility Operating License Number DPR-58 and DPR-74) for a period of 20 years beyond the current license expiration dates of midnight, October 25, 2014, and December 23, 2017, for Units 1 and 2, respectively. The CNP site is located along the eastern shore of Lake Michigan in Lake Charter Township, Berrien County, Michigan. The NRC issued the CNP construction permit for Units 1 and 2 on March 25, 1974, and the operating license for Units 1 and 2 on October 25, 1974, and December 23, 1977, respectively. Units 1 and 2 of CNP consist of Westinghouse Electric pressurized-water reactors (PWRs) licensed to generate 3304 and 3468 megawatts-thermal (MWt), or approximately 1080 and 1155 megawatts-electric (MWe), respectively. Details concerning the plant and the site appear in the Updated Final Safety Analysis Report (UFSAR).

The license renewal process consists of two concurrent reviews, including a technical review of safety issues and an environmental review. The NRC regulations at 10 CFR Part 54 and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," respectively, state the requirements for these reviews. The safety review for the CNP license renewal is based on the applicant's license renewal application (LRA) and on the responses to requests for additional information (RAIs) from the staff. During audits and meetings and in docketed correspondence, the applicant supplemented its responses to the LRA and RAIs. Unless otherwise noted, the staff reviewed and considered information submitted through March 24, 2005. The staff reviewed information received after that date on a case-by-case basis, depending on the stage of the safety review and the volume and complexity of the information. 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 O1-F21, Rockville, Maryland, 20852-2738 (301-415-4737/800-397-4209), at the Bridgman Public Library in Bridgman, Michigan, and at the St. Joseph Maud Preston Palenske Memorial Library in St. Joseph, Michigan. Materials related to the LRA are also available through the NRC's Web site, at http://www.nrc.gov.

This SER summarizes the results of the staff's safety review of the CNP LRA and delineates the scope of the technical details considered in evaluating the safety aspects of the CNP proposal to operate for an additional 20 years beyond the term of the current operating license. The staff reviewed the LRA 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" (SRP-LR), issued July 2001.

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

Appendix A to this SER identifies the applicant's commitments associated with the renewal of the operating licenses. Appendix B provides a chronology of the NRC's and the applicant's principal correspondence related to the review of the application. Appendix C gives the references used during the course of the review. Appendix D lists the principal contributors to the SER.

In accordance with 10 CFR Part 51, the staff prepared a draft for comment, and a final plant-specific supplement to the Generic Environmental Impact Statement (GEIS) that discusses the environmental considerations related to renewing the license for CNP, Units 1 and 2. The staff issued NUREG-1437, Supplement 20, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Donald C. Cook Nuclear Plant, Units No. 1 and 2, Final Report," in May 2005.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, the NRC issues licenses for commercial power reactors to operate 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—not because of technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC held a workshop on nuclear power plant aging, in anticipation of the interest in license renewal. That workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. On the basis of that research, a technical review group concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the NRC published the 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, the NRC amended the License Renewal Rule in 1995. 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, the NRC amended 10 CFR Part 54 to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The Rule changes ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the changes clarified and simplified the integrated plant assessment (IPA) process to ensure consistency with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort and developed 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal in fulfilling 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 key 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 plant SSCs in the period of extended operation, and possibly a few other issues related to safety during the period of extended operation.

(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 to include those SSCs (1) that are safety related, (2) whose failure could affect safety related functions, and (3) that are relied on to demonstrate compliance with the NRC's regulations for fire protection (FP), environmental qualification (EQ), pressurized thermal shock, anticipated transients without scram, 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 subject to an aging management review (AMR). The 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 qualified life or specified time period. As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that it will manage the effects of aging in such a way that the intended function or functions of those SCs 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 aging effects that may occur for active equipment are more readily detectable and will be identified and corrected through routine surveillance and maintenance or revealed through performance indicators. The surveillance and maintenance programs for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required throughout the period of extended operation. Pursuant to 10 CFR 54.21(d), a supplement to the final safety analysis report (FSAR) must contain a summary description of the programs and activities for managing the effects of aging.

The Rule also requires an applicant to identify and update time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the length of time the plant will operate. These assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must either show that these calculations will remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that it will adequately manage the effects of aging on these SSCs for the period of extended operation.

In July 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 RG endorses an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the License Renewal Rule. The NEI guideline is NEI 95-10, Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," issued March 2001. The NRC also prepared the SRP-LR, which the staff used to review this application.

The applicant used the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued July 2001. The GALL Report provides the staff with a summary of staff-approved aging management programs (AMPs) for the aging of many SCs that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the staff can greatly reduce the time, effort, and resources used to review an applicant's LRA, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited with managing aging for most of the SCs used throughout the industry and serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined will adequately manage aging during the period of extended operation.

1.2.2 Environmental Review

The environmental protection regulations are governed by 10 CFR Part 51. The NRC revised these regulations 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 the licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. Subpart A of Appendix B, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant," to 10 CFR Part 51 identifies these generic findings as Category 1 issues. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. The environmental report must include analyses of those environmental impacts that must be evaluated on a plant-specific basis (Category 2 issues) 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 the existence of new and significant information not considered in the GEIS. The staff held a public meeting on November 20, 2003, in Bridgman, Michigan, as part of the NRC's scoping process, to identify environmental issues specific to the plant. Results of the environmental review and a preliminary recommendation for the license renewal action appear in the NRC's draft plant-specific supplement to the GEIS, which the NRC issued on September 17, 2004, and discussed at a separate public meeting on November 9, 2004, in Bridgman, Michigan. After consideration of comments on the draft, the NRC will prepare and publish a final plant-specific supplement to the GEIS. These documents are published separately from this report.

1.3 Principal Review Matters

The staff performed its technical review of the CNP LRA in accordance with Commission guidance, the requirements for renewing operating licenses for nuclear power plants in 10 CFR Part 54, and the specific standards for license renewal in 10 CFR 54.29, "Standards for Issuance of a Renewed License." 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 of its LRA for CNP, submitted by letter dated October 31, 2003. The staff finds that the applicant has submitted the information required by 10 CFR 54.19(a) in Section 1 of the LRA.

In 10 CFR 54.19(b), the Commission requires that LRAs 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 stated the following in its LRA regarding this issue:

> 10 CFR 54.19(b) 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 current indemnity agreement (No. B-61) for CNP states, in Article VII, that the agreement shall terminate at the time of expiration of the license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as revised by Amendment No. 7, lists CNP special nuclear material licenses SNM-1301 and SNM-1753, and operating licenses DPR-58 and DPR-74. I&M requests that conforming changes be made to Article VII of the indemnity agreement, and Item 3 of the Attachment to that agreement, specifying the extension of agreement to the expiration date of the renewed CNP facility operating licenses sought in this application. In addition, should the license numbers be changed upon issuance of the renewal license, I&M requests that conforming changes be made to Item 3 of the Attachment to the indemnity agreement, and to other sections of the agreement as deemed appropriate.

The staff intends to maintain the license numbers upon issuance of the renewed licenses. Therefore, conforming changes to the indemnity agreement are not necessary, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, "Contents of Application—Technical Information," 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 3 and 4 and Appendices A and B to 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, the applicant must submit an amendment to the renewal application. In the amendment, the applicant must identify any change to the CLB of the facility that materially affects the contents of the LRA, including the FSAR Supplement.

In accordance with 10 CFR 54.22, "Contents of Application—Technical Specifications," an applicant must include in the LRA any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation. In Appendix D to the LRA, the applicant stated that no changes to the CNP technical specifications are necessary. This satisfies the requirement specified in 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 technical information appears in Sections 2, 3, and 4 of this report.

The staff will document its evaluation of the environmental information required by 10 CFR 54.23, "Contents of Application—Environmental Information," in the final plant-specific supplement to the GEIS that specifies the considerations related to renewing the licenses for CNP. The staff will prepare this supplement separately from this SER. As required by 10 CFR 54.25, "Report of the Advisory Committee on Reactor Safeguards," the ACRS will issue a report documenting its evaluation of the staff's LRA review and associated SER. Section 5 of this SER will incorporate this ACRS report. Section 6 of this SER will document the findings required by 10 CFR 54.29.

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 are intended to contribute to the NRC's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. The NRC documents the lessons learned in interim staff guidance (ISG) documents and issues them to the public for comment, modifies them as necessary to resolve comments, reissues them in final, and makes them available for use by the staff and interested stakeholders until the improved license renewal guidance documents are revised.

Table 1-1 presents the current set of relevant ISGs issued by the staff and the SER sections in which the staff addresses these issues.

Table 1-1 Relevant Interim Staff Guidance

ISG Issue (Approved ISG No.)	Purpose	SER Section
Station Blackout Scoping (ISG-2)	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. The recovery time for offsite power is much faster than that of emergency diesel generators (EDGs). The offsite power system should be within the scope of license renewal.	2.1.3.1.2, 3.6.2.3.4
Concrete Aging Management Program (ISG-3)	Lessons learned from the GALL demonstration project indicate that the GALL Report is not clear whether concrete requires any AMPs.	3.5.2.1.1, 3.5.2.2
Fire Protection System Piping (ISG-4)	The ISG clarifies the staff position for wall thinning of FP piping system in GALL AMPs XI.M26 and XI.M27. The new position states that there is no need to disassemble FP piping, as oxygen can be introduced in the FP piping, which can accelerate corrosion. Instead, use a nonintrusive method such as volumetric inspection. Sprinkler heads should be tested every 50 years and 10 years after initial service. The ISG eliminates halon/carbon dioxide system inspections for charging pressure, valve lineups, and automatic mode of operation test from the GALL Report, as the staff considers these test verifications to be operational activities.	3.0.3.2.5, 3.0.3.2.6

ISG Issue (Approved ISG No.)	Purpose	SER Section
Identification and Treatment of Electrical Fuse Holder (ISG-5)	The ISG includes the 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.	2.1.3.1.4, 3.6.2.3.3
Revision to GALL (ISG-15)	The ISG clarifies and incorporates NEI's proposed revision to GALL AMP XI.E2 (i.e, replaced technical specification surveillance with specific calibrations or surveillance).	3.0.3.2.9, 3.6.2.1.1

1.5 Summary of Open Items

As a result of its review of the LRA for CNP, including additional information submitted to the NRC through November 19, 2004, the staff identified two issues that remained open at the time the SER with Open Items was published. The staff considers an issue open if the applicant has not presented a sufficient basis for resolution, or if the staff has not yet reviewed information provided in recent submittals from the applicant. Each open item has a unique identifying number. By letter dated January 21, 2005, the applicant responded to these open items. The staff reviewed the responses and has closed out each of the open items. The basis for closing the open items is as follows:

Item Description

3.3.2.1.11-1 The staff did not find the applicant's initial response to RAI 3.3.2.1.11-1 acceptable. The staff's specific concern, described in RAI 3.3.2.1.11-1, is the apparent aging management of the internal environments of components/systems by visual inspection of external surfaces if environmental differences exist between internal and external surfaces. While external inspection of component condition (e.g. pipes, valves) can indicate the components' internal condition, this is generally not the case until internal degradation results in loss of component integrity as might be indicated by a system leak. The applicant has not provided sufficient information to demonstrate that aging effects on internal surfaces of various components in miscellaneous systems will be effectively managed by the System Walkdown Program. The staff asked the applicant to provide further justification for the use of the System Walkdown Program to manage aging effects for all components identified in LRA Table 3.3.2-11 with different internal and external environments sufficiently to maintain the intended function of the components and ensure that operation of safety related equipment will not be jeopardized during the period of license renewal.

Resolution

By letter dated January 21, 2005, the applicant provided additional information in response to Open Item 3.3.2.1.11-1.

As shown in LRA Table 3.3.2-11, in addition to System Walkdown Program, the Water Chemistry Control Program will manage the effects of aging on the components with an internal environment of treated water, except for level glass gauges and molded plastic tanks. Because the glass in the level gauges is inherently resistant to potential aging effects in air, treated water, raw or untreated water, or untreated borated water environments, it has no aging effects requiring management. The molded plastic tanks in the ice condenser system are exposed to an internal treated water environment (i.e., glycol mixture) that is monitored by the Auxiliary Systems Water Chemistry Control Program described in LRA Section B.1.40.3.

Additionally, as indicated in LRA Table 3.3.2-11, the Flow-Accelerated Corrosion Program will also manage the effects of aging on components with an internal steam environment, except for copper heater coils, cast iron strainer housings and carbon steel traps. I&M will include the auxiliary steam system copper heater coils, cast iron strainer housings, and carbon steel traps exposed to an internal steam environment in the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41.

The remaining components in LRA Table 3.3.2-11 with differing internal and external environments that credit only the System Walkdown Program for aging management are exposed to internal raw or untreated water environments. The following table identifies the fluid-filled mechanical systems that contain these components.

SYSTEM CODE	SYSTEM NAME
CF	Chemical Feed
CONT	Containment
DRAIN	Process Drains
LTW	Lake Township Water
NESW	Non-Essential Service Water
NS	Nuclear Sampling
PASS	Post-Accident Sampling

SYSTEM CODE	SYSTEM NAME
RMS	Radiation Monitoring
RWD	Radioactive Waste Disposal
SD	Station Drainage

The following discussion provides additional basis for acceptability of other programs for managing the effects of aging on the CF, LTW, NESW, and NS systems that have components containing raw or untreated water.

1. The CF system contains water treated with chemicals to reduce corrosion in the steam generators. This environment was conservatively classified as untreated water although it is actually chemically treated.

2. The LTW system contains water that has been chemically treated by the municipality prior to being used at the site, but was conservatively classified as untreated water in the aging management review. Because LTW chemistry is not controlled by CNP, a chemistry control program was not credited in the LRA. However, as documented in I&M's supplemental response to RAI 3.3.2.1.9-6 in this letter, the extent of aging effects on security diesel system components containing LTW will be confirmed by the Chemistry One-Time Inspection Program, which will inspect a representative sample of 10 CFR 54.4(a)(2) components in the LTW system.

3. The NS system contains heat exchangers exposed to an internal raw water (NESW) environment. The NESW system has the same suction source and is chemically treated in the same manner as the essential service water (ESW) system. The Service Water System Reliability Program will manage the effects of aging on 10 CFR 54.4(a)(2) components containing NESW, because these components are fabricated from the same materials and are exposed to the same environments as components in the ESW system.

The remaining systems (CONT, DRAIN, PASS, RMS, RWD, and SD) have copper alloy, carbon steel, stainless steel, or glass components that may be pressurized and contain raw or untreated water. As discussed previously, glass exposed to raw or untreated water exhibits no aging effects requiring management. I&M will include these 10 CFR 54.4(a)(2) components that are subject to aging management review in the Chemistry One-Time Inspection Program.

Loss of material, if any, from the 10 CFR 54.4(a)(2) components discussed above is expected to progress slowly. The one-time inspection of these components will provide assurance that loss of material is occurring at a rate slow enough to ensure that the intended functions of the components will be maintained during the period of extended operation. This one-time inspection will be performed near the end of the current operating term. The visual inspections will identify indications of loss of material. If loss of material is identified, an evaluation will be performed to confirm that the rate is sufficiently slow that loss of intended function will not occur during the period of extended operation. For material and environment combinations with no evidence of loss of material or with very gradual loss of material, no further actions will be taken. For material and environment combinations with loss of material rates such that loss of intended function could occur during the period of extended operation, corrective actions will be taken in accordance with the Corrective Action Program. Appropriate corrective actions may consist of component replacement or additional inspections for components with the material and environment combination in which the excessive loss of material is found.

The supplemental response is reasonable and acceptable to the staff because the applicant has provided sufficient information to demonstrate that aging effects on internal surfaces of various components in miscellaneous systems will be effectively managed by the application of a combination of the Flow-Accelerated Corrosion Program, Chemistry One-Time Inspection Program and the Service Water System Reliability Program. The application of the One-Time Inspection Program is appropriate for those components where loss of material is expected to progress slowly and the applicant has identified that the inspection will be performed near the end of the current operating term with appropriate corrective actions. On the basis of the supplemental information submitted by the applicant, all issues related to Open Item 3.3.2.1.11-1 are resolved. The application of the Chemistry One-Time Inspection Program discussed above is specified in Commitment #39 in Appendix A of this SER.

B.1.12-1

In CNP LRA, Appendix B, Section B.1.12, the applicant states that CNP AMP B1.12, "Flow-Accelerated Corrosion Program," is consistent with GALL AMP XI.M17. During the audits and inspections, the staff noted that CNP's Flow-Accelerated Corrosion (FAC) Program is consistent but with an exception. The Monitoring and Trending element of GALL AMP XI.M17 requires that if degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning. However, CNP's FAC program bases its sample expansion determination on a threshold criteria rather than on predicted thickness. Sample size is increased when inspections detect significant FAC wear resulting in a wall thickness threshold of less than or equal to 60 percent of nominal wall thickness. In RAI B.1.12-1, the staff requested that the applicant provide a description of the FAC Program, as modified by the exception, and justification for the exception regarding the criteria for performing additional examinations by expanding the sample size.

Resolution

By letter dated January 21, 2005, the CNP provided additional information in response to RAI B.1.12-1, indicating that the AMP is consistent with GALL, with an exception.

In the FAC Program description in GALL Section XI.M17, the Monitoring and Trending section states, in part, that, "If degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning." CNP stated that literal implementation of this statement from the GALL description is not practical in many cases. If very little degradation is predicted, measured wall thickness may be less than the predicted thickness even though the calculated life of the affected component may exceed the operating life of the plant. In this case, sample expansion would not be warranted. Therefore, the applicant took an exception to the Monitoring and Trending attribute of GALL, Section XI.M17.

The staff noted that the CNP FAC Program is based on industry guidance in the Electric Power Research Institute (EPRI) report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," dated April 1999, which recommends increasing the sample size when inspections of the sample detect significant FAC wear. In the CNP FAC Program, significant FAC wear is defined as FAC resulting in a wall thickness of less than or equal to 60 percent of nominal wall thickness. Sample expansion is typically required if any component is determined to have a wall thickness of less than or equal to 60 percent of nominal wall thickness (must be greater than allowed minimum wall thickness). In addition, the staff noted that CNP FAC procedures require that a sample expansion be performed when inspection results indicate that a component has a remaining life less than one operating cycle based on a trending of wall thickness measurements. This covers situations where the minimum wall thickness required may be greater than 60 percent of nominal wall thickness.

The staff found this exception to GALL for sample expansion to be acceptable because literal implementation of the sample expansion criterion is not practical in all cases, particularly when the predicted wall thickness change is small and the change is close to the measurement capabilities. Additionally, the staff finds this exception acceptable since the applicant trends expected wall thinning values and requires that the projected acceptable wall thickness be above a threshold value that is above 60% nominal wall and above minimum wall. On the basis of the supplemental information submitted by the applicant, all issues related to RAI B.1.12-1 are resolved.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA for CNP, including additional information submitted to the NRC through November 19, 2004, the staff identified the two issues that remained confirmatory items at the time the SER with Open Items was published. Confirmatory items are items for which the staff and the applicant had reached a satisfactory resolution, but the applicant had not yet formally submitted a resolution to the staff. By letter dated January 21, 2005, the applicant responded to these items. The staff reviewed the responses and has closed each of the confirmatory items. The basis for closing the confirmatory items is as follows:

Item	Description
4.3-1	The applicant provided a UFSAR supplement description of the Fatigue Monitoring Program (FMP) in Section A.2.1.12 of the LRA and a description of its

TLAA evaluation for Class 1 and non-Class 1 component fatigue analyses in Section A.2.2.2 of the LRA. The staff requested that the applicant update Section A.2.2.2 to include the following: (1) a discussion of each of the actions selected for commitment to evaluate the auxiliary spray line piping and (2) a discussion of each of the actions selected for commitment to evaluate the environmental fatigue of the safety injection nozzles, charging nozzles and the RHR line.

Resolution The applicant's January 21, 2005, response provided the updated UFSAR Supplement for Section A.2.2.2. The updated UFSAR Supplement contains a discussion of the applicant's commitment to perform additional actions to address fatigue of the auxiliary spray line piping prior to the period of extended operation and its commitment to perform additional actions to address environmental fatigue of the pressurizer surge line, safety injection nozzles, charging nozzles and the RHR line prior to the period of extended operation. The staff considered these additional proposed actions and found them acceptable. The staff concludes that the revised UFSAR Supplement adequately describes the applicant's actions to address metal fatigue. Therefore, Confirmatory Item 4.3-1 is closed. The above mentioned commitments are specified in Commitment #40, #31, #33, and #35 in Appendix A of this SER.

4.6-1 The applicant provided a UFSAR supplement describing its TLAA evaluation for containment liner plate and penetration fatigue analyses in Section A.2.2.4 of the LRA. The staff requested that the applicant update the UFSAR Supplement to capture its commitment to analyze the containment penetrations.

Resolution The applicant's January 21, 2005, response provided the updated UFSAR Supplement for Section A.2.2.4. The updated UFSAR Supplement contains a discussion of the applicant's commitment to analyze the containment penetrations. The staff concludes that the revised UFSAR Supplement adequately describes the applicant's actions to address the containment liner plate and penetration fatigue analyses. Therefore, Confirmatory Item 4.6-1 is closed. The above mentioned commitment is Commitment # 34 in Appendix A of this SER.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the CNP LRA, including the additional information and clarifications submitted subsequently, the staff identified three proposed license conditions.

The first license condition requires the applicant to include the UFSAR Supplement required by 10 CFR 54.21(d) in the next UFSAR update required by 10 CFR 50.71(e) following the issuance of the renewed license.

The second license condition requires that the future activities identified in the UFSAR Supplement be completed prior to entering the period of extended operation.

The following describes the third license condition:

> All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion.

2. STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54), specifically 10 CFR 54.21, "Contents of Application—Technical Information," requires that each application for license renewal contain an integrated plant assessment (IPA). The IPA must list and identify those structures, systems, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an aging management review (AMR).

In Section 2.1, "Scoping and Screening Methodology," of the license renewal application (LRA), the applicant described the scoping and screening methodology used to identify the SSCs at the Donald C. Cook Nuclear Power Plant (CNP) that are within the scope of license renewal and subject to an AMR. The staff reviews the applicant's scoping and screening methodology to determine if it meets the scoping requirements in 10 CFR 54.4(a) and the AMR screening requirements stated in 10 CFR 54.21(a)(1).

In developing the scoping and screening methodology for the CNP LRA, the applicant considered the requirements of 10 CFR Part 54, the Statements of Consideration related to the License Renewal Rule, and the guidance provided in Nuclear Energy Institute (NEI) 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule." In addition, the applicant also considered the Nuclear Regulatory Commission (NRC) staff's license renewal interim staff guidance (ISG) documents and related correspondence.

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 of the LRA, "Scoping and Screening Methodology," 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 SSCs that are subject to an AMR as required by 10 CFR 54.21(a)(1). Additionally, LRA 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 Systems," provide results of this process and identify structures and components (SCs) subject to an AMR.

2.1.2.1 Scoping Methodology

In Section 2.1 of the LRA, the applicant described the methodology it used to scope mechanical, structural, and electrical and instrumentation and controls (I&C) SSCs pursuant to the scoping criteria of 10 CFR 54.4(a). The following sections describe the applicant's scoping methodology, as described in the LRA.

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

The applicant described the general approach to scoping safety related, nonsafety related, and systems and structures credited with demonstrating compliance with certain regulated events in Section 2.1.1, "Scoping Methodology," of the LRA. The applicant stated that, consistent with NEI 95-10, the scoping process used for the CNP license renewal project began with a list of plant systems and structures. The applicant then identified the functions performed by these systems and structures and determined which of these functions met the scoping criteria of 10 CFR 54.4(a). The following sections describe the scoping approaches specific to the 10 CFR 54.4(a) scoping criteria for safety related SSCs, nonsafety related SSCs, and SSCs required to mitigate regulated events.

Application of the Scoping Criteria in 10 CFR 54.4(a)(1). In Section 2.1.1.1, "Application of Safety related Scoping Criteria," of the LRA, the applicant discussed the methodology used to identify SSCs meeting the 10 CFR 54.4(a)(1) safety related license renewal scoping criteria. The applicant stated that it reviewed system and structure functions and considered them to be a safety intended function if one or more of the three safety related scoping criteria of 10 CFR 54.4(a)(1) were met. The applicant placed systems or structures that perform a safety related intended function within the scope of license renewal. However, the applicant stated that, because of plant-specific considerations or preferences, some components may have been classified as safety related that do not have safety related intended functions. Consequently, the applicant noted that it could treat an SSC that does not meet the 10 CFR 54.4(a)(1) safety related scoping criteria as safety related under other CNP programs for plant-specific reasons.

Application of the Scoping Criteria in 10 CFR 54.4(a)(2). In Sections 2.1.1.2, "Application of Criterion for Nonsafety related SSCs Whose Failure Could Prevent the Accomplishment of Safety Functions," and 2.1.3, "Interim Staff Guidance Discussion," of the LRA, the applicant discussed the methodology used to identify systems and structures meeting the 10 CFR 54.4(a)(2) nonsafety related license renewal scoping criteria. The applicant considered the following three categories of nonsafety related systems and structures when performing 10 CFR 54.4(a)(2) scoping evaluations:

(1) nonsafety related equipment required to remain functional in support of a safety related function

(2) nonsafety related SSCs directly connected to safety related SSCs, and

(3) nonsafety related SSCs that are not directly connected to safety related SSCs but have the potential for adverse spatial interactions with safety related equipment.

The applicant described the methods used to scope each of these categories of nonsafety related systems and structures in LRA Section 2.1.1.2.

Nonsafety related SSCs Required to Support Safety related SSCs

In Section 2.1.1.2.1, "Functional Failures of Nonsafety related SSCs," of the LRA, the applicant noted that, with few exceptions, it classified SSCs required to perform a function in support of other safety related components as safety related and included them within the scope of license renewal under the 10 CFR 54.4(a)(1) scoping criteria. However, the applicant stated that, for the few exceptions in which nonsafety related equipment is required to remain functional to support a safety function, the supporting systems were included within the scope of license renewal.

Nonsafety related SSCs Directly Connected to Safety related SSCs

The applicant described the scoping of nonsafety related SSCs directly attached to safety related piping in Section 2.1.1.2.2, "Spatial Failures of Nonsafety related SSCs," of the LRA. The applicant stated that, for piping systems, the nonsafety related piping and supports up to and including the first equivalent anchor beyond the safety/nonsafety interface are within the scope of license renewal and subject to an AMR. In addition, nonsafety related portions of safety related systems downstream of the first anchor are subject to an AMR if they have the potential for spatial interaction with safety related SSCs.

Nonsafety related SSCs Not Directly Connected to Safety related SSCs with the Potential for Spatial Interaction

The applicant described the scoping of nonsafety related SSCs that could spatially interact with safety related equipment but are not physically connected to a safety related system. The applicant stated that it considered the following types of nonsafety related spatial interactions during scoping:

- physical impact, such as in a seismic event
- pipe whip
- jet impingement
- harsh environment resulting from a piping rupture
- damage resulting from leakage, spray, or flooding

The applicant described the use of both mitigative and preventive approaches for scoping nonsafety related equipment in the LRA. The mitigative approach relied upon installed protective features (*i.e.*, whip restraints, spray shields, supports, barriers) to protect safety related SSCs against spatial interaction with nonsafety related SSCs. The applicant stated that such protective features credited in the plant design are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2). In thjose cases in which protective features provide adequate protection, the applicant excluded nonsafety related SSCs from the scope of license renewal. The applicant stated that nonsafety related SSCs that provide flood barriers to safety related SSCs (*i.e.*, walls, curbs, dikes, or doors) are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2). Additionally, the applicant stated that inherent nonsafety related features that protect safety related equipment from missiles generated from internal or external events are within the scope of license renewal based on the 10 CFR 54.4(a)(2) criteria.

In Section 2.1.1.2.2 of the LRA, the applicant described how the scoping process considered the impact on falling equipment from load handling malfunctions and failed piping segments. The LRA stated that overhead-handling systems from which a load drop could result in damage to any system that could prevent the accomplishment of a safety related function are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2). However, the applicant concluded that (1) no earthquake experience data exist of welded steel pipe segments falling as a result of a strong motion earthquake, and (2) falling of piping segments is extremely rare and only occurs when there is a pipe support failure. The applicant therefore concluded that, as long as the effects of aging on the supports for welded steel piping systems were managed, falling sections of piping are not a credible scenario. Consequently, although the applicant considered the effects of spray and leakage, it did not consider the piping section to be within scope for 10 CFR 54.4(a)(2) because of the physical impact hazard.

The applicant concluded that spatial interactions of pipe whip, jet impingement, and harsh environment are credible only for high-energy systems. Therefore, the applicant stated that, if a high-energy line break (HELB) analysis assumes that a nonsafety related piping system does not fail, or assumes failure only at specific locations, then that piping system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2) and is subject to an AMR to provide reasonable assurance that those assumptions remain valid throughout the period of extended operation. The applicant noted that moderate- and low-energy systems have the potential for spatial interactions of spray and leakage. Nonsafety related systems and nonsafety related portions of safety related systems with the potential for spray or leakage that could prevent safety related SSCs from performing required safety functions are considered within the scope of license renewal based on the 10 CFR 54.4(a)(2) criteria. However, the LRA states that long-term exposure to conditions resulting from a failed nonsafety related SSC (such as leakage or spray) are not considered credible. The applicant stated that it would detect leakage or spray from liquid-filled low-energy systems during routine operator rounds or system walkdowns before such leakage or spray could impact the performance of safety related equipment. Followup actions would direct leakage away from equipment to prevent failure, and the applicant will perform evaluations of the condition of the piping.

The applicant stated that operating experience indicates that nonsafety related systems containing only air or gas have experienced no failures because of aging that could impact the ability of safety related equipment to perform required safety functions. Consequently, the applicant determined that air and gas (nonliquid) systems are not a hazard to other plant equipment and that these systems are not within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2).

<u>Application of the Scoping Criteria in 10 CFR 54.4(a)(3)</u>. In Sections 2.1.1.3, "Application of Criterion for Regulated Events," and 2.1.3, "Interim Staff Guidance Discussion," of the LRA, the applicant discussed the methodology used to identify SSCs credited for performing a function that demonstrates compliance with regulations for fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram (ATWS), and station blackout (SBO) pursuant to the 10 CFR 54.4(a)(3) license renewal scoping criteria. The following sections describe the applicant's approaches for scoping systems and structures required to mitigate each of these five regulated events.

Fire Protection

The applicant described the scoping of SSCs required to demonstrate compliance with the FP requirements of 10 CFR 50.48 in Section 2.1.1.3.1, "Fire Protection (10 CFR 50.48)," of the LRA. The applicant stated that it performed a detailed review of the current licensing basis (CLB) for FP. The applicant placed SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to the safe operation of the plant within the scope of license renewal, and the applicant identified the associated intended functions on which it relied.

Environmental Qualification

The applicant described the scoping of SSCs required to demonstrate compliance with the EQ requirements of 10 CFR 50.49 in LRA Section 2.1.1.3.2, "Environmental Qualification (10 CFR 50.49)." Electrical equipment important to safety that is required to be environmentally qualified to mitigate certain accidents that would result in harsh environmental conditions in the plant is defined in 10 CFR 50.49. The applicant stated that, because it used a bounding approach for electrical equipment scoping, it included all electrical systems and electrical equipment in mechanical systems within the scope of license renewal. Consequently, the applicant concluded that all environmentally qualified equipment is within the scope of license renewal based ib tge criteria of 10 CFR 54.4(a)(3).

Pressurized Thermal Shock

The applicant described the scoping of SSCs required to demonstrate compliance with the PTS requirements of 10 CFR 50.61 in Section 2.1.1.3.3, "Pressurized Thermal Shock (10 CFR 50.61)," of the LRA. The applicant stated that the only system relied upon to meet the PTS regulation is the reactor coolant system (RCS), which contains the reactor vessel. Furthermore, the applicant concluded that it did not rely upon any structures to meet the requirements of 10 CFR 50.61.

Anticipated Transients Without Scram

The applicant described the scoping of SSCs required to demonstrate compliance with the ATWS requirements of 10 CFR 50.62 in Section 2.1.1.3.4, "Anticipated Transients without Scram (10 CFR 50.62)," of the LRA. The applicant stated that, based on a review of the CLB for ATWS, it determined the intended functions supporting the 10 CFR 50.62 requirements. The applicant noted that the plant systems supporting compliance with the requirements of 10 CFR 50.62 are primarily electrical and I&C systems. However, the applicant indicated that the intended function for the main turbine (MT) also supports 10 CFR 50.62 requirements.

Station Blackout

The applicant described the scoping of SSCs required to demonstrate compliance with the SBO requirements of 10 CFR 50.63 in Section 2.1.1.3.5, "Station Blackout (10 CFR 50.63)," of the LRA. The applicant noted that the scope of equipment relied upon to support 10 CFR 50.63 is that required to ensure that the reactor core is cooled and containment integrity is maintained during the 4-hour coping duration before offsite or onsite alternating current (ac) power is restored. The applicant stated that, based on the review of the CLB for SBO, it identified the equipment performing intended functions required for compliance with 10 CFR 50.63.

2.1.2.1.2 Documentation Sources Used for Scoping and Screening

In Section 2.1.1, "Scoping Methodology," of the LRA, the applicant described the information sources reviewed during the license renewal scoping and screening process. The applicant stated that the key information sources that form the CLB for the CNP include the updated final safety analysis report (UFSAR), technical specifications, and docketed licensing correspondence. The applicant noted that it used these CLB documents, as well as the following information sources, to identify the systems and structures list:

- The facility database (FDB) contains records of component and equipment items for which the safety related status and procurement grades have been determined and verified. In addition to identifying the component name, unique identification number, and safety classification, FDB records also include information pertaining to plant maintenance and operation.

- The applicant used civil/structural plant layout drawings.

Functions for structures and mechanical systems were identified based on reviews of CLB documentation and other information sources, including the following:

- The Maintenance Rule Program database describes the systems and system functions to demonstrate that the SSCs scoped into the Maintenance Rule are monitored in accordance with 10 CFR 50.65. The database also includes the Maintenance Rule scoping documents. The applicant used the Maintenance Rule systems and functions as part of the starting point in the scoping effort.

- The Expanded System Readiness Review (ESRR) program assessed the conformance of the plant design, testing, maintenance, operation, and configuration with the licensing and design-basis requirements. The applicant used the ESRR reports as a resource for system descriptions and identification of SSC functions.

The applicant stated that the intent of the document review was to identify all major system functions to provide reasonable assurance that all license renewal functions were identified.

2.1.2.1.3 System, Structure, and Component Level Scoping

In Sections 2.1.1, "Scoping Methodology," and 2.1.2, "Screening Methodology," of the LRA, the applicant described the scoping methodology for systems and structures that are safety related, nonsafety related, or relied upon to perform a function to demonstrate compliance with the regulated events described in 10 CFR 54.4(a)(3). The applicant considered scoping as the process of identifying systems and structures that perform a license renewal intended function. The licensee did not describe a component-level scoping process in the LRA, but instead performed a component-level scoping as an integral part of the screening process.

As its starting point for the scoping process, the applicant created a list of systems and structures using the CLB and other information sources. After creating the system and structure list and identifying associated functions, the applicant then determined which systems and structures perform license renewal intended functions. In the LRA, the applicant described the different approaches it used to scope mechanical systems, electrical and I&C systems, and structures in accordance with 10 CFR 54.4(a). The sections below describe the scoping methodology for each of these component classifications.

<u>Mechanical System and Component Scoping Methodology</u>. As described in Section 2.1.1 of the LRA, the applicant determined which of those functions performed by plant mechanical systems meet any of the three criteria of 10 CFR 54.4(a). Functions that meet any of the 10 CFR 54.4(a) scoping criteria are considered intended functions for license renewal, and the applicant included systems that performed these intended functions within the scope of license renewal. Although the applicant's scoping methodology as described in the LRA does not show

a process for scoping individual mechanical components, Section 2.1.2.1, "Screening of Mechanical Components," of the LRA states that, for each mechanical system within the scope of license renewal, the screening process identified those components subject to an AMR. To determine which components are subject to an AMR, the applicant identified system evaluation boundaries to show those portions of the mechanical system necessary to ensure that the intended functions of the system would be performed. As described in Section 2.1.2.1.1, "Determining Evaluation Boundaries," of the LRA, the applicant included components needed to support each of the system-level intended functions identified in the scoping process within the system evaluation boundary. The applicant stated that the determination of the system evaluation boundary required an understanding of system operations in support of the intended functions. This process was based on the CLB, plant-specific experience, appropriate industry-wide operating experience, and design documents (*e.g.* calculations, drawings).

Structure and Structural Component Scoping Methodology. As described in Section 2.1.1 of the LRA, the applicant determined those functions performed by plant structures which meet the scoping criteria of 10 CFR 54.4(a). The applicant considered functions that met any of the 10 CFR 54.4(a) scoping criteria as intended functions for license renewal and included the associated structure within the scope of license renewal. As described in Section 2.1.2.2.3, "Intended Function," of the LRA, the intended functions for structures are typically based on a simple set of functions that apply both to the structure and to its components and commodities. Although the applicant's scoping methodology as described in the LRA does not describe a process for scoping individual structural components, Section 2.1.2.2, "Screening of Structural Members and Components," of the LRA states that, for each structure within the scope of license renewal, the screening process identified components and commodities subject to an AMR. The applicant stated that the screening process for structural components and commodities involved a review of design documents (*i.e.*, UFSAR and drawings) to identify specific structural components and commodities that constitute the structure. The applicant then categorized structural components and commodities with no unique identifiers into groupings based on materials of construction.

Electrical and Instrumentation and Control System and Component Scoping Methodology. The applicant described the methodology used to scope electrical and I&C systems in Section 2.1.1, "Scoping Methodology," Section 2.1.2.3, "Screening of Electrical and Instrumentation and Control Components," and Section 2.5, "Scoping And Screening Results: Electrical and Instrumentation and Control Systems," of the LRA. The applicant stated that it used a bounding scoping approach for electrical equipment. Using this approach, the applicant included plant electrical and I&C systems, as well as electrical and I&C components in mechanical systems, within the scope of license renewal. Under this scoping approach, the applicant did not consider system-level intended functions of electrical and I&C components.

The applicant stated that it grouped the total population of electrical components into commodity groups that included electrical and I&C components with common characteristics. The applicant then identified component-level intended functions of these commodity groups. The applicant subjected the electrical commodity groups to further screening to identify component types subject to an AMR.

2.1.2.2 Screening Methodology

Following the identification of SSCs within the scope of license renewal, the applicant implemented a process for determining which SSCs would be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). In Section 2.1.2, "Screening Methodology," of the LRA, the applicant stated that the screening process for a structure or component within the scope of license renewal determined the following:

- whether the structure or component performs a component intended function without moving parts and without a change in configuration or properties (*i.e.*, it is passive)
- whether the structure or component is not subject to replacement based on a qualified life or specified time period (*i.e.*, it is long-lived)

Screening activities identified mechanical, structural, and electrical and I&C components within the scope of license renewal and subject to an AMR. The following describes the applicant's screening methodology identified in the LRA for mechanical, structural, and electrical and I&C components.

2.1.2.2.1 Mechanical Component Screening

Following mechanical system scoping, the applicant performed screening to identify those mechanical components that are subject to an AMR. The applicant stated in LRA Section 2.1.2.1.2, "Identifying Components Subject to Aging Management Review," that long-lived passive components that perform or support an intended function without moving parts or a change in configuration or properties are subject to an AMR. Additionally, the applicant stated that, in the case of valves, pumps, fans, and dampers, the valve bodies, pump casings, and housings for fans and dampers perform an intended function by maintaining the pressure boundary and are therefore subject to an AMR.

If the mechanical component is not subject to replacement based on a qualified life or specified time period, the applicant considered it long-lived. As stated in the LRA, component replacement programs are based on vendor recommendations, plant experience, or any means that establishes a specific service life, qualified life, or replacement frequency under a controlled program.

The applicant created license renewal drawings to indicate on mechanical flow diagrams those components within the system evaluation boundaries requiring an AMR. However, the applicant noted that the drawings do not generally include components within the scope of license renewal based solely on the criterion of 10 CFR 54.4(a)(2).

2.1.2.2.2 Structural Component Screening

Following component level scoping for structures, the applicant performed screening to identify those structural components that are subject to an AMR. In Section 2.1.2.2, "Screening of Structural Members and Components," of the LRA, the applicant described the methodology used to screen structural components. The applicant stated that structural components or commodities subject to an AMR are those that perform an intended function without moving parts or a change in configuration or properties (*i.e.*, passive) and are not subject to replacement based on qualified life or specified time period (*i.e.*, long-lived). The applicant noted that, since structures are inherently passive, and with few exceptions are long-lived, it based the screening of structural components and commodities primarily on whether they perform an intended function.

2.1.2.2.3 Electrical and Instrumentation and Control Component Screening

In Sections 2.1.2.3 and 2.5 of the LRA, the applicant described the methodology used to screen electrical and I&C components. The applicant stated in Section 2.1.2.3.3, "Long-Lived Screening," that electrical components included in the Environmental Qualification Program pursuant to 10 CFR 50.49 are replaced based on a qualified life. As such, they do not meet the "long-lived" criterion of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. Therefore, the applicant concluded that AMRs involve only non-EQ electrical and I&C components.

In Section 2.1.2.3.2, "Passive Screening," of the LRA, the applicant noted that it cross-referenced electrical commodity groups to the appropriate NEI 95-10 commodity to identify the passive commodity groups. The applicant identified two passive electrical and I&C commodity groups that meet the 10 CFR 54.21(a)(1)(i) criterion (*i.e.*, components performing an intended function without moving parts or without a change in configuration)—(1) cables and connections, bus, electrical portions of electrical and I&C penetration assemblies and (2) high-voltage insulators. The applicant concluded that other electrical and I&C commodity groups are active and not subject to an AMR.

2.1.2.2.4 Commodity Group Component Screening

In Section 2.1.2.4, "Identification of Short-Lived Components and Consumables," of the LRA, the applicant described the generic screening results for several types of short-lived components and consumables. The applicant determined that consumables and short-lived components, such as packing, gaskets, component seals, and O-rings; oil, grease and filters; fire extinguishers, fire hoses, and air packs are not subject to an AMR.

2.1.3 Staff Evaluation

The staff evaluated the LRA scoping and screening methodology in accordance with the guidance contained in Section 2.1, "Scoping and Screening Methodology," of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued July 2001 (hereafter referred to as the SRP-LR). The staff based the acceptance criteria for the scoping and screening methodology review on the following regulations:

- 10 CFR 54.4(a), as it relates to the identification of plant SSCs within the scope of the rule
- 10 CFR 54.4(b), as it relates to the identification of the intended functions of plant SSCs determined to be within the scope of the rule
- 10 CFR 54.21(a)(1) and (a)(2), as they relate to the methods utilized by the applicant to identify plant structures and components subject to an AMR

As part of the review of the applicant's scoping and screening methodology, the NRC staff reviewed the activities described in the following sections of the LRA using the guidance in the SRP-LR:

- Section 2.1, "Scoping and Screening Methodology," to ensure that the applicant described a process for identifying SSCs 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, "Scoping and Screening Results: Electrical and Instrumentation and Control Systems," to assure the applicant described a process for determining structural, mechanical, and electrical components at the CNP that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2)

In addition, the staff conducted a scoping and screening methodology audit at the Indiana Michigan Power Company (I&M) engineering offices in Buchanan, Michigan, from January 13–16, 2004. The audit focused on ensuring that the applicant 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 10 CFR Part 54. The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology that the applicant implemented. In addition, the staff conducted detailed discussions with the applicant on the implementation and control of the license renewal program. The staff also reviewed administrative control documentation and selected design documentation that the applicant used during the scoping and screening process. The staff further reviewed a sample of system scoping and screening results reports for the ice condenser, auxiliary feedwater, emergency core cooling, and main feedwater systems to ensure that the applicant appropriately implemented the methodology outlined in the administrative controls and that the results are consistent with the CLB. The staff documented its review in an audit report issued on September 8, 2004. The report identified several issues which required additional information from the applicant prior to completion of the review effort. Each of these issues is identified and addressed in detail in Section 2.1 of this safety evaluation.

2.1.3.1 Scoping Methodology

The staff reviewed the scoping process to verify the consistency of the applicant's methodology with the SRP-LR and other documented staff positions and that the scoping methodology adequately identified SSCs within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a).

2.1.3.1.1 Implementation Procedures and Documentation Sources Used for Scoping and Screening

The staff reviewed the applicant's scoping and screening implementation procedures to verify that the process used to identify SCs subject to an AMR is consistent with the LRA and the SRP-LR and that the applicant appropriately implemented the procedural guidance.

Additionally, the staff reviewed the scope of CLB documentation sources used to support the LRA development and the process the applicant used to ensure that CLB commitments were appropriately considered during the scoping and screening process.

Scoping and Screening Implementation Procedures. The staff reviewed the following scoping and screening methodology implementation procedures and engineering reports:

- License Renewal Project Guideline (LRP-PG)-01, "Scoping Systems and Structures"
- LRP-PG-02, "License Renewal Program Plan"
- LRP-PG-03, "Structural Screening and Aging Management Reviews"
- LRP-PG-04, "Mechanical System Screening and Aging Management Reviews"
- LRP-PG-05, "Electrical System Scoping, Screening and Aging Management Reviews"
- LRP-PG-14, "10 CFR 54.4(a)(2) Nonsafety related SSC Affecting Safety related SSC"
- License Renewal Project Mechanical Aging Management Report (LRP-MAMR)-35, "Aging Management Review of Nonsafety related Systems and Components Affecting Safety related Systems"

In reviewing these procedures, the staff focused on the consistency of the detailed procedural guidance with information in the LRA and the various NRC staff positions documented in the SRP-LR and ISG documents. The staff found that the applicant's scoping and screening methodology instructions and procedures are generally consistent with Section 2.1 of the LRA and are of sufficient detail to provide the applicant's staff with consistent guidance on the scoping and screening implementation process to be followed during the LRA activities.

Quality Assurance Controls Applied to LRA Development. The staff reviewed the quality assurance (QA) controls used by the applicant to provide reasonable confidence that the LRA scoping and screening methodologies were adequately implemented. The applicant utilized the following QA processes during the LRA development:

- Implementation of the scoping and screening methodology was governed by written procedures and guidelines.

- Although much of the LRA development was performed by contractors, the applicant developed procedures to govern the conduct of owner acceptance reviews of contractor work products. For example, License Renewal Project Guideline LRP-PG-12, "Owner's Acceptance Reviews," describes the process used by the applicant to review license renewal project documents provided by Framatome/Entergy. Documents subject to this acceptance review included AMR reports, time-limited aging analyses (TLAAs), and aging management program (AMP) evaluation reports.

- The Nuclear Safety Review Board and the Plant Operations Review committee reviewed and approved the LRA before the applicant submitted it to the NRC. Additionally, the applicant developed procedural guidance for a final review of the LRA prior to submittal to the NRC.

- The applicant planned to retain certain license renewal documents, such as aging management reports, individual system scoping reports, time-limited aging analyses, and topical reports, as quality records.

- The applicant performed a peer review and two self assessments of license renewal activities.

The staff concluded that these QA activities, which exceed current regulatory requirements, provide additional assurance that the applicant performed the LRA development activities in a manner consistent with the LRA descriptions.

Training for License Renewal Project Personnel. The staff reviewed the applicant's implemented training process to ensure that the guidelines and methodology for the scoping and screening activities would be performed in a consistent and appropriate manner. The staff found the training of the license renewal project team to be incremental, iterative, and adapted to the needs of the tasks to be performed. Initially, a core group of three persons was trained by being required to read a family of documents and certify that they had done so. That family of 28 documents is listed in Attachment 6, "Training Requirements," to LRP-PG-02, "License Renewal Program Plan." The second group of personnel trained were subject matter experts. Everyone working on the license renewal project was given, at a minimum, overview-level training. Trainees numbered about 100, including American Electric Power (AEP) employees, contractors working directly on the project, and Framatome and Entergy subcontractors. Formal classroom training from 2 to 8 hours was provided; for example, the former was provided to managers, the latter, to in-depth participants. The training focused on the level necessary to perform assigned tasks. The training requirements were categorized in the LRP-PG-02 training requirements matrix pursuant to license renewal project personnel who prepared or reviewed various documents, such as scoping documents, AMRs, program evaluations, TLAAs, and the LRA, and among site personnel who reviewed or approved those documents. Completed training was documented on individual "License Renewal Training Documentation" forms, also from Attachment 6 to LRP-PG-02. Periodic meetings were held with various system owners to provide understanding of issues and proposed solutions. The staff interviewed LRA team members and concluded they were very knowledgeable of requirements and activities associated with scoping and screening.

On the basis of its discussions with the applicant's license renewal project team responsible for the scoping and screening process, as well as a review of selected design documentation in support of the process, the staff concluded that the applicant's staff understood the requirements of the scoping and screening methodology and adequately implemented such methodology in the renewal application. The staff did not identify any significant concerns regarding the training of the applicant's license renewal project team or contractors.

Sources of Current Licensing Basis Information. The staff reviewed the scope and depth of the applicant's CLB review to verify that the methodology was sufficiently comprehensive to identify SSCs within the scope of license renewal and SCs requiring an AMR. As defined in 10 CFR 54.3(a), the CLB is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis that are docketed and in effect. The CLB includes certain NRC regulations, orders, license conditions, exemptions, technical specifications, design-basis information documented in the most recent final safety evaluation report (SER), and licensee commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports (LERs).

The staff determined that Section 2.1.1 of the LRA provides a description of the CLB and related documents used during the scoping and screening process that is consistent with the guidance contained in the SRP-LR and NEI 95-10. Specifically, Section 2.1.1 of the LRA identifies the UFSAR, technical specifications, docketed licensing correspondence, the Facility Database (FDB), plant layout drawings, the Maintenance Rule database, and ESRR reports, as information sources used during scoping. Additionally, in Section 5.4 of scoping implementation procedure LRP-PG-01, the applicant provided a comprehensive listing of documents that it could use to support scoping and screening evaluations. The applicant identified system functions based on its review of the applicable sections of the UFSAR, technical specifications, Maintenance Rule scoping document, initial and final ESRR reports, design-basis documents (DBDs), and license renewal topical reports. During the methodology audit, the applicant stated that, although some of these documents are not considered to be a part of the CLB (such as the Maintenance Rule scoping documents, ESRR reports, and DBDs), it used them to identify potential CLB functions and additional CLB references.

The CNP FDB is the applicant's primary repository for component safety classification information. During the audit, the staff reviewed the applicant's administrative controls for FDB safety classification data and concluded that the applicant had established adequate measures to control the integrity and reliability of FDB safety classification data. Therefore, the staff concluded that the FDB provides a sufficiently controlled source of component data to support scoping and screening evaluations.

In the LRA, the applicant showed topical reports as a source of information to support identification of systems and structures relied upon to demonstrate compliance with the five regulated events referenced in 10 CFR 54.4(a)(3). Procedure LRP-PG-06, "License Renewal Topical Reports," provides guidance for preparing, reviewing, issuing, and maintaining topical reports. Procedure LRP-PG-06 also identifies a listing of potential CLB information sources that is consistent with Section 2.1.1 of the LRA. Additionally, LRP-PG-06 includes specific guidance for the format and content of a topical report, report review, and approval. The inspectors concluded that LRP-PG-06 provides sufficient guidance to reasonably ensure that topical reports adequately summarize CLB information for the purposes of scoping.

In addition to the sources referenced above, the applicant used its corrective action database to review site-specific operating experience. Since mid-1997, the applicant maintained an electronically searchable condition report (CR) database. By performing keyword searches of the CR database, the applicant identified pertinent site-specific operating experience within the Corrective Action Program. Although the database may not include CRs written before mid-1997, the staff determined that the use of the CR database, in combination with other data sources, including CLB documents and ESRR reports, provides reasonable assurance that the applicant adequately considered site-specific operating experience during scoping and screening evaluations.

Conclusion

Based on a review of information provided in Section 2.1 of the LRA, a review of the applicant's detailed scoping and screening implementation procedures, and the results from the scoping and screening audit, the staff concluded that the applicant's scoping and screening methodology considered a sufficient scope and depth of CLB information. The staff determined that the CLB documentation review methodology is capable of identifying SSC intended functions in a manner consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21.

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

The staff evaluated the applicant's methodology for scoping safety related and nonsafety related SSCs and SSCs relied upon to demonstrate compliance with regulated events pursuant to the requirements of 10 CFR 54.4(a). The following describes the results of this staff evaluation.

Application of the Scoping Criteria in 10 CFR 54.4(a)(1). Pursuant to 10 CFR 54.4(a)(1), the applicant must consider as within the scope of license renewal all safety related SSCs which are relied upon to remain functional during and following design-basis events (DBEs) to ensure: (1) the integrity of the reactor coolant pressure boundary (RCPB), (2) the ability to shut down the reactor and maintain it in a safe-shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which 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.

With regard to identifying DBEs, Section 2.1.3, "Review Procedures," of the SRP-LR, states the following:

> The set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of design basis events that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high-energy-line break.

During the audit, the NRC staff questioned how the applicant considered nonaccident DBEs during scoping, particularly DBEs that may not be described in the UFSAR. The applicant identified the DBEs applicable to CNP, including external hazards such as fire, earthquakes, flooding, wind and missiles, and HELBs. The staff concluded that the applicant considered a scope of DBEs consistent with the guidance contained in the SRP-LR.

The applicant performed scoping of safety related SSCs in accordance with the implementation Sections 5.2 and 5.4 of procedure LRP-PG-01. The applicant classified SSCs as either safety related or nonsafety related using the safety classification field in the FDB. Section 5.2 of LRP-PG-01 requires that the applicant review the FDB safety classification field to ensure that any system or structure that has a component identified as safety related is considered for inclusion in the scope of the license renewal project. The staff reviewed the safety classification criteria used to determine the FDB safety classification to verify consistency with the 10 CFR 54.4(a)(1) criteria. The staff determined that the nuclear safety related definition the applicant used in its safety classification program does not include all the exposure limitations referenced in 10 CFR 54(a)(1)(iii). Specifically, CNP Procedure 12-EHP-5043-SCD-001, "Safety Classification Determinations," does not include a reference to the offsite exposure limitations in 10 CFR 50.67(b)(2) for use of an alternate source term (AST).

RAI 2.1-1

In discussions with the CNP license renewal project team, the NRC staff noted that the applicant previously submitted a license amendment application to allow use of the AST methodology for control room habitability dose analyses. The staff subsequently approved use of the AST for control room habitability dose evaluations. At the time of the audit, the applicant had not decided to pursue an amendment for use of the AST methodology for offsite dose evaluations. Therefore, in Request for Additional Information (RAI) 2.1-1, the staff asked the applicant to describe how it factored the use of the AST methodology for control room operator dose into its scoping evaluations. In particular, the staff requested that the applicant identify the impact of the alternate source methodology on the scoping of safety related SSCs pursuant to 10 CFR 54.4(a)(1). Additionally, with regard to the potential future use of the AST methodology for offsite dose analysis, the staff requested that the applicant describe its plans for evaluating the license renewal scoping impact should it request a future license amendment to use the AST methodology for offsite dose analysis.

The applicant responded to RAI 2.1-1 in a letter dated May 7, 2004. The applicant stated that the use of the AST method, as approved in the Unit 1 License Amendments 258 and 271 and Unit 2 License Amendments 241 and 252, does not impact the scoping of safety related SSCs pursuant to 10 CFR 54.4(a)(1). The use of the AST methodology affects operating limits and analysis input parameters, which in turn affects some equipment performance requirements. However, the applicant stated that the AST methodology did not establish any new equipment functional requirements in that no new or different equipment is credited for the revised control room dose analyses, and no new or different operational modes are required of equipment already credited in the analyses. Furthermore, the applicant stated that, if it should pursue a license amendment to apply the AST methodology to offsite dose analysis in the future, it will evaluate any changes to equipment functional requirements that would result from the new analyses in accordance with established design control processes. If an additional license amendment regarding AST should occur before issuance of a renewed operating license, the applicant stated that it will evaluate the resultant changes to the CLB and determine if they materially affect the contents of the LRA, and if so, address them in accordance with the requirements of 10 CFR 54.21(b). The staff concluded that the applicant adequately addressed the staff's concern regarding the use of the AST methodology during scoping evaluations. In particular, the staff determined that the applicant adequately considered the impact of the AST methodology on safety related scoping evaluations conducted pursuant to 10 CFR 54.4(a)(1). On this basis, RAI 2.1-1 is resolved.

RAI 2.1-2

The applicant's scoping guidance noted that a system or structure may not perform an 10 CFR 54.4(a)(1) intended function even though the system or structure is classified as safety related for plant-specific purposes. In these cases, LRP-PG-01 allows the applicant to exclude the SSC from the scope of safety related SSCs considered under license renewal. However, LRP-PG-01 states that the applicant must still evaluate the SSC for inclusion within the scope of license renewal under the criteria in 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3). During the audit, the staff reviewed the process that the applicant used to evaluate components classified as safety related in the FDB that did not perform a safety related license renewal intended function. The applicant reevaluated the FDB safety-classification of many safety related components to reconcile differences between license renewal scoping determinations and FDB information. In RAI 2.1-2, the staff requested that the applicant describe the process used to evaluate components classified as safety related that were determined not to perform a safety related intended function. In particular, the staff requested the following:

(1) The applicant should describe any components or structures classified as safety related in the facility safety-classification database that are not included within the scope of license renewal under the 10 CFR 54.4(a)(1) criteria.

(2) In reviewing the scoping results for the component cooling water (CCW) system, the staff identified that the applicant did not include several safety related components on the miscellaneous cooling header within the scope of license renewal. Therefore, the staff requested a description of how the applicant addressed components originally classified as safety related in the CCW miscellaneous header during scoping evaluations.

(3) The applicant should describe the process used to reconcile the FDB safety classification information with scoping intended function determinations. In particular, the staff requested additional information about the scope of the review used to reevaluate the safety-classification of SSCs to reconcile disparities with intended function determinations.

The applicant responded to RAI 2.1-2 by letter dated May 7, 2004. In its response, the applicant noted that the scoping process identified some passive, long-lived mechanical components (mostly small valves) classified in the FDB as safety related that do not appear to perform a safety related support function. However, the applicant noted that the FDB is not used as the primary basis for inclusion of components subject to aging management; rather it is used as a tool to confirm that all components with a safety related function are properly and correctly subjected to an AMR. To reconcile differences between scoping conclusions and FDB information, the applicant stated that it wrote Corrective Action Program condition reports to track safety classification determinations (SCDs) and the FDB updates. In its RAI response, the applicant also described the process used to revise the safety classification information in the FDB. The applicant stated that plant procedures control revisions to FDB safety classification information and include a review of design documents describing the functions and the safety classification of the component.

In February 2003, after completion of the AMR reports, the applicant performed a comprehensive comparison of the mechanical components classified as safety related in the FDB but not subject to an AMR to those components (thermowells, valves, and conoseals) that are subject to an AMR. The applicant subsequently included these additional components in the AMR reports, as applicable. The applicant also stated that SSCs classified as safety related in the FDB that do not perform a safety related license renewal intended function are generally identified in the Corrective Action Program for further evaluation under the SCD process.

The applicant performed a similar comparison in January 2004. The applicant stated that the January 2004 comparison identified a few passive, long-lived mechanical components associated with the CCW system miscellaneous header that do not perform a safety related intended function but have not been reclassified from safety related to nonsafety related. However, the applicant noted that these CCW system components are subject to an AMR for

10 CFR 54.4(a)(2) considerations. Additionally, the applicant stated that the January 2004 comparison identified a small number of system components classified as safety related in the FDB (typically valves, thermowells, flex hoses, and dampers) in several systems that do not perform a safety related intended function as defined in 10 CFR 54.4(a)(1). In its RAI response, the applicant identified these specific component types and provided a basis for the conclusion that they do not perform a safety related intended function. The applicant stated that it conservatively classified these components as safety related in the FDB and may consider them for future safety classification downgrades. However, in some cases, the applicant noted that these components may perform an intended function as defined under 10 CFR 54.4(a)(2) and therefore are considered within the scope of license renewal. In summary, the applicant concluded that it found all long-lived, passive mechanical components that perform a 10 CFR 54.4(a)(1) intended function to be subject to an AMR.

The staff concluded that the applicant provided an adequate basis for its determination that certain equipment classified as safety related in the FDB does not perform a safety related intended function. In particular, the staff noted that the applicant performed two comparison reviews to identify safety related equipment that may have been omitted from the scoping process, tracked discrepancies between scoping determinations and the FDB in the Corrective Action Program, and systematically revised FDB safety-classification data. The staff determined that these measures provided reasonable assurance that SSCs performing a safety related intended function pursuant to 10 CFR 50.54(a)(1) are included within the scope of license renewal. On this basis, RAI 2.1-2 is resolved.

The applicant implemented the safety related scoping process through the use of a system function scoping question checklist. In accordance with Section 5.4 of LRP-PG-01, for each identified system or structure function the applicant asked safety related scoping questions pursuant to a scoping checklist to determine if the function met the scoping criteria of 10 CFR 54.4(a)(1). The staff reviewed the safety related scoping questions and concluded that they are consistent with the requirements of 10 CFR 54.4(a)(1).

To provide additional assurance that the applicant adequately implemented its safety related scoping methodology, the NRC methodology staff reviewed a sample of the license renewal scoping results for the ice condenser, auxiliary feedwater, emergency core cooling, and main feedwater systems. The staff concluded that the applicant adequately implemented its 10 CFR 54.4(a)(1) scoping process. Additionally, the staff determined that the applicant identified and used pertinent engineering and licensing information to support the scoping determinations for the items sampled.

Conclusion. On the basis of a review of the applicant's methodology and evaluation of a sampling of scoping results, the staff concluded that the applicant's safety related scoping methodology provides reasonable assurance that the applicant included SSCs meeting the scoping criteria of 10 CFR 54.4(a)(1) within the scope of license renewal. Specifically, the staff concluded that the applicant considered an adequate set of DBEs and used reasonable methods for identifying safety related intended functions.

Application of the Scoping Criteria in 10 CFR 54.4(a)(2). As required by 10 CFR 54.4(a)(2), the applicant must consider all nonsafety related SSCs, the failure of which could prevent satisfactory accomplishment of any safety related functions identified in 10 CFR 54.4(a)(1), to be within the scope of license renewal. As described in the SRP-LR, the applicant must identify those nonsafety related SSCs (including certain support systems) failures of which are considered in the CLB and could prevent accomplishment of the safety related functions identified in 10 CFR 54.4(a)(1).

The staff provided further expectations for determining what SSCs meet the 10 CFR 54.4(a)(2) criterion in letters dated December 3, 2001, and March 15, 2002. In the December 3, 2001 letter, the staff describes the expectation that both seismic II/I piping segments and their supports should be included within the scope of license renewal under the 10 CFR 54.4(a)(2) criterion. Additionally, the letter provides specific examples of operating experience which identify 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) criterion. The March 15, 2002 letter further describes the staff's expectations regarding how the applicant should determine which nonsafety related SSCs could adversely impact intended functions and therefore be within the scope of license renewal. The staff's position states that applicants should not consider hypothetical failures; rather, applicants 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 industrywide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific CRs, industry reports such as significant operating event reports, and engineering evaluations.

The applicant documented its methodology for performing 10 CFR 54.4(a)(2) scoping of nonsafety related SSCs in implementation procedures LRP-PG-01, LRP-PG-14, and LRP-MAMR-35. The applicant performed nonsafety related license renewal scoping in a two-stage process. The first stage of the process considered nonsafety related equipment that either provided a support function to a safety related intended function or was directly attached to a safety related system. The second stage of the process, which considered spatial interactions between nonsafety related equipment and safety related SSCs, addressed the staff expectations described in the December 3, 2001 and March 15, 2002 guidance letters. During the second stage of 10 CFR 54.4(a)(2) scoping, the applicant considered spatial interactions, including leakage, spray, and flooding; physical impact; and pipe whip, jet impingement, or harsh environments. The remainder of this section describes the applicant's approach for addressing each of these 10 CFR 54.4(a)(2) scoping aspects.

Nonsafety related Support Equipment

Scoping methodology implementing procedure LRP-PG-01, Section 5.3, states that nonsafety related systems and structures that directly support the function of a safety related system or structure, or the failure of which could prevent the performance of a safety related function, are within the scope of license renewal. Scoping implementation procedure LRP-PG-01 notes that the plant's CLB, actual plant-specific operating experience, industrywide operating experience, and existing plant-specific engineering evaluations should be considered to determine the appropriate systems and structures meeting the criteria of 10 CFR 54.4(a)(2). This methodology approach is consistent with Section 2.1.1.2.1 of the LRA, which states that for the cases in which nonsafety related equipment is required to remain functional in support of a safety function, the supporting systems are included within the scope of license renewal. The staff concluded that the applicant considered an adequate scope of CLB information and implemented a reasonable approach for scoping of nonsafety related SSCs that provide support functions to safety related intended functions.

Nonsafety related Piping Attached to Safety related SSCs

In the SRP-LR, Section 2.1.3.1.2 indicates instances in which an entire pipe run containing both safety related and nonsafety related piping and associated piping anchors may have been analyzed as part of the CLB to establish that it could withstand DBE loads. If this is the case, a failure of the nonsafety related portion of the pipe run or the associated piping anchors could render the safety related portion of the piping unable to perform its intended function. The SRP-LR states that in these cases the applicant's methodology would include (1) the remaining nonsafety related piping up to its anchors and (2) the associated piping anchors as being within the scope of license renewal under 10 CFR 54.4(a)(2).

Scoping implementation procedure LRP-PG-14, Section 5.1 states that for piping systems, the nonsafety piping and supports, up to and including the first equivalent anchor beyond the safety/nonsafety interface, are within the scope of license renewal and subject to an AMR. During the scoping methodology audit, the applicant stated that it defined the first equivalent anchor as one level of restraint in each of the three orthogonal directions. The applicant stated that this definition of equivalent anchor is consistent with its CLB. Specifically, Section 2.9.3, "Seismic Design Criteria for Seismic Class I and II Piping," of the UFSAR, states that if a piping system consists of a combination of seismic Class I, Class II, and/or Class III piping, the piping model may be structurally decoupled at an anchor or a point (or points) encompassing restraints in the three orthogonal directions.

RAI 2.1-3

The staff concluded that the applicant's methodology to extend the scoping boundary of nonsafety related piping attached to safety related systems to the first level of restraint in each orthogonal direction is consistent with the applicant's CLB and the SRP-LR. However, during the methodology audit, the applicant stated that the location of the first equivalent anchor point was not physically located in the as-built plant. Therefore, in RAI 2.1-3(a), the staff requested additional information regarding the process the applicant used to ensure that it adequately considered all nonsafety-components and structures between the safety/nonsafety interface and the first equivalent anchor point during scoping. In particular, the staff requested that the applicant describe the method it used to ensure that all material/environment combinations between the safety/nonsafety interface and the first equivalent anchor during an AMR were considered.

The applicant responded to RAI 2.1-3(a) by letter dated May 7, 2004. The applicant stated that it showed the safety/nonsafety interface on the LRA drawings; however, the staff found that these drawings do not show the exact location of the equivalent anchor. The applicant stated that it included all material and environmental combinations in the LRA AMR summary tables to assure that a review of systems within the scope of license renewal for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3), as well as 10 CFR 54.4(a)(2), was performed. The applicant traced piping from the license renewal boundary back to an obvious anchor point (*i.e.*, a larger line or a larger component, such as a pump or heat exchanger) to identify piping classification changes. The applicant reviewed piping classifications beyond the license renewal boundaries indicated on the drawings for these systems to ensure that no new material or environmental combinations existed. The applicant determined that this approach assured that the piping reviewed would include the first equivalent anchor. If the applicant identified a piping material or environmental change, the applicant compared it with the AMR results for that system or a connected system to validate that the material and environmental combination was addressed. The applicant concluded that this review confirmed that LRA Section 3.0, "Aging Management Review Results," includes all applicable material and environmental combinations up to and including the first equivalent anchor.

In reviewing the applicant's response to RAI 2.1-3(a), the staff could not determine if the applicant used a consistent definition of an equivalent anchor throughout the scoping process. Specifically, the applicant reviewed piping drawings up to an obvious anchor point (*i.e.*, a larger line or a larger component, such as a pump or heat exchanger), but it did not provide sufficient information for the staff to verify that this anchor adequately bounded the equivalent anchor point as defined by restraint in each of the three orthogonal directions. Furthermore, it was not clear from the applicant's response that the scope of license renewal included larger components providing piping support functions to nonsafety related piping attached to safety related piping. In particular, if a major component performs an intended function by providing an equivalent anchorage point for attached piping, the applicant should include the major component within the scope of license renewal. Therefore, the staff asked the applicant to provide additional clarification regarding the definition it used for the equivalent anchorage point, the scoping method used for SSCs that constitute an equivalent anchorage point, and clarification regarding the basis for its determination that the review approach described in the RAI 2.1-3(a) response adequately bounded all SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

On May 17, 2004 and May 21, 2004, the staff held conference calls with the applicant to discuss the RAI and to provide further clarification of the staff's requested information. As a result of those conference calls, the applicant provided a supplemental response to RAI 2.1-3 in a letter dated August 11, 2004. The applicant's response stated that the definition for equivalent anchor is a point or points encompassing restraints in three orthogonal directions. This definition is consistent with the CLB and is described in Section 2.9.3 of the applicant's UFSAR. In addition, the applicant clarified that there were cases in which nonsafety related piping attached directly to safety related piping terminated at a major component (*i.e.,* plant equipment that is anchored to a structure such that all 6 degrees of freedom of a piping system are restrained). For those cases, that major component was considered within scope because it provided the nonsafety related piping anchorage, and was subject to an aging management program (*i.e.*, LRA Section B.1.32, Structures Monitoring Program).

The staff concluded that the applicant provided an adequate basis for its determination of the equivalent anchor location consistent with the plant CLB, and the identification of plant equipment providing nonsafety related piping anchorage. On the above basis, RAI 2.1-3(a) is resolved.

Leakage, Spray, or Flooding

The applicant considered spatial interactions between safety related and nonsafety related equipment that are either not directly attached to a safety related system or do not provide a supporting function for a safety related intended function during the second stage of 10 CFR 54.4(a)(2) scoping. The applicant considered certain spatial interactions to be credible, including leakage or spray, physical impact from falling or missile generation, and HELBs. To address the effects of leakage, spray, and flooding, the applicant used a bounding spaces approach to identify nonsafety related equipment that could spatially interact with safety related SSCs. The 10 CFR 54.4(a)(2) scoping process described in LRP-PG-14, Section 7.0, "Scoping/screening Method to Address 10 CFR 54.4(a)(2)," and LRP-MAMR-35, Section 2.2.4, "Leakage, Spray, Flooding," includes the following steps:

- The applicant identified the safety-related structures using the civil/structural aging management review reports (AMRRs). The safety related structures at the CNP site include the containment building, auxiliary building, screen house and the portion of the turbine building that contains the auxiliary feedwater pumps. During the methodology audit, the applicant confirmed that plant equipment performing a safety related intended function is located within a safety related structure.

- Through the use of plant layout drawings and CNP FDB component location information, the applicant identified systems in safety related structures containing liquid or steam. The applicant considered only systems with nonsafety-related components in the safety-related structures for inclusion within scope for 10 CFR 54.4(a)(2). The applicant eliminated systems containing safety-related components with an AMRR prepared that have no nonsafety-related components, the failure of which could impact safety-related SSCs from further review, since they are already within scope for 10 CFR 54.4(a)(1)(i–iii).

- The applicant eliminated nonsafety-related systems and nonsafety-related portions of safety-related systems if justification was provided that their failure cannot adversely impact the performance of safety functions. This justification may rely on system walkdowns or drawing and database reviews.

- The applicant placed systems determined to have components, the failure of which could adversely impact the performance of safety functions, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Only the components in those systems with the potential for spatial interaction with safety-related equipment are subject to an AMR.

- The applicant then performed an AMR of the component commodity types in nonsafety-related systems or nonsafety-related portions of systems with the potential for adverse spatial interaction with safety-related SSCs. Using the generic AMR, the applicant identified AMPs for managing the aging effects of the material and environment combinations.

- The applicant documented the results of the scoping for 10 CFR 54.4(a)(2) in the license renewal information system database. Additionally, LRP-MAMR-3 documents the results of the spatial interaction review for 10 CFR 54.4(a)(2) scoping.

Although the applicant's spaces approach for 10 CFR 54.4(a)(2) scoping appears to provide bounding results, the staff determined that this methodology includes several assumptions that could potentially limit the range of spatial interactions between nonsafety related and safety related equipment considered by the applicant. Specifically, Section 5.2.3, "Leakage, Spray, or Flooding," of LRP-PG-14 and Section 2.1.1.2.2 of the LRA state that long-term exposure to conditions resulting from a failed nonsafety related SSC (such as leakage or spray) is not considered credible. This conclusion is based on the applicant's assumption that leakage and spray from liquid-filled low-energy systems would be detected during routine operator rounds or system walkdowns before it could impact the performance of safety-related equipment. Furthermore, the staff determined that the applicant's spaces approach for scoping nonsafety related equipment in accordance with 10 CFR 54.4(a)(2) appears to be based, in part, upon the assumption that both active and passive safety related equipment can withstand short-term wetting without loss of intended function. Because the LRA clearly describes the basis for these assumptions, the staff requested, in RAI 2.1-3(b), that the applicant clarify its position and methodology relative to the consideration of spray and wetting of safety related SSCs resulting from the failure of nonsafety related equipment. Specifically, the staff requested the applicant to address the following:

- The staff requested clarification of the applicant's basis for its determination that long-term exposure to conditions resulting from a failed nonsafety related SSC is not considered credible. Specifically, the staff requested the applicant to address if it excluded nonsafety-related SSCs from the scope of license renewal based on the applicant's determination that long-term exposure of safety related SSCs to conditions resulting from failed nonsafety related equipment (*i.e.*, wetting or spray) is not considered credible.

- The staff requested a description of how the applicant considered the effects of short-term wetting and spray on passive and active safety related SSCs during 10 CFR 54.4(a)(2) scoping. Furthermore, if it assumed that safety related SSCs could withstand short-term spray or wetting without loss of intended function, the staff requested the applicant to describe the basis for this assumption.

- The staff asked the applicant if it used the System Walkdown Program described in Section B.1.38, "System Walkdown," of the LRA as the sole AMP for any nonsafety related structures or components that could potentially spatially interact with safety related SSCs. If the System Walkdown Program alone manages the effects of aging for any nonsafety related SSC, the staff requested the applicant to describe how it considered the effects of short-term spray and wetting during scoping and AMR evaluations.

The applicant responded to RAI 2.1-3(b) by letter dated May 7, 2004. Although the applicant acknowledged that LRA Section 2.1.1.2.2 states that long-term exposure to conditions resulting from a failed nonsafety related SSC (such as leakage or spray) is not considered credible, it did not apply this conclusion during its scoping evaluations. If a steam or liquid-filled nonsafety related system (or nonsafety related portion of a safety related system) is in a safety related building, then the applicant considered that system to be within the scope of 10 CFR 54.4(a)(2), regardless of potential exposure duration. The applicant did not exclude nonsafety related SSCs from the scope of license renewal based on the consideration that long-term exposure to conditions resulting from a failed nonsafety related SSC is not credible. Additionally, the applicant stated that it considered the potential for wetting or spray on passive and active safety related components in its scoping evaluations. The applicant also considered nonsafety related systems containing steam or liquid that are near safety related equipment as within the scope of 10 CFR 54.4(a)(2), regardless of potential exposure duration. Further, the applicant stated that it did not apply an assumption that safety related SSCs could withstand short-term spray or wetting without loss of intended function during scoping or screening. However, the applicant determined that the System Walkdown Program, as described in Section B.1.38 of Appendix B to the LRA, is adequate since it requires periodic walkdowns that would detect and correct failures caused by long-term exposure to spray or wetting. Active safety related component failures resulting from short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule, and the applicant would take appropriate corrective actions.

In reviewing the applicant's RAI response, the staff determined that the applicant's bounding scoping approach includes an adequate range of nonsafety related SSCs that perform a 10 CFR 54.4(a)(2) intended function. In particular, the applicant clarified that it considered the potential for wetting or spray on passive and active safety related components in scoping evaluations, did not use potential exposure duration to exclude SSCs from the scope, and, if a steam or liquid-filled nonsafety related system (or nonsafety related portion of a safety related system) was in a safety related building, that system was considered within the scope of 10 CFR 54.4(a)(2). The staff concluded that this approach is consistent with the 10 CFR 54.4(a)(2) scoping guidance contained in the SRP-LR and the staff's December 3, 2001, and March 15, 2002, interim guidance letters. However, the staff notes that the sole use of a system walkdown AMP for aging management of a nonsafety related SSC that could spatially interact with safety related SSCs might, in certain circumstances, result in the loss of a safety related intended function. In particular, the applicant's RAI response indicates that the Corrective Action Program and Maintenance Rule Program would be used to correct safety related SSC failures caused by short-term spatial interactions. The staff questioned whether reliance on the Corrective Action Program to correct a safety related intended function failure because of an age-related nonsafety related SSC failure constitutes adequate implementation of either a mitigative or preventive approach to 10 CFR 54.4(a)(2) scoping, as described in the staff's March 15, 2002 letter. In particular, the staff lacked sufficient information to conclude that the applicant would consider and manage the effects of aging on nonsafety related SSCs in a manner that would provide reasonable assurance that the safety related SSCs will be able to perform their intended functions. Despite this concern, the staff determined that the applicant, through the use of the spaces approach to scoping, identified the nonsafety SSCs of concern within the scope of license renewal. Consequently, this issue is more closely associated with the review of AMP adequacy than with the scoping methodology. Therefore, Open Item 3.3.2.1.11-1, discussed in Section 3.3.2.3.11 of this report, addresses the concerns associated with the potential for loss of safety related intended functions because of age-related failure of nonsafety related SSCs. Because the staff concluded that the applicant's spaces approach to 10 CFR 54.4(a)(2) scoping adequately identified nonsafety related SSCs with the potential to spatially interact with safety related SSCs, RAI 2.1-3(b) is resolved.

The applicant generically excluded certain nonsafety related gas-filled systems from the scope of license renewal based on the determination that there is no credible mechanism for these systems to adversely impact safety related SSCs. The applicant based this determination on a review of CLB information and operating experience. Section 2.1, "Operating Experience Review," of LRP-MAMR-35 states that the applicant reviewed Corrective Action Program databases dating from October 1997 to October 2002. The applicant used keyword searches to identify corrective action documents related to leak, spray, seep and rupture. The applicant stated that it reviewed each condition report description if it appeared to contain information relative to the intent of the search. Based on this review, the applicant found no instances of failures in air/gas systems that either caused the failure of other plant equipment or had the potential of adversely affecting safety-related plant equipment. The applicant stated that it also reviewed generic NRC industry operating experience and found no items describing instances in which nonsafety related air/gas system leakage or ruptures adversely impacted safety-related equipment.

During the scoping and screening methodology audit, the applicant indicated that it based the 5-year timeframe for operating experience review, in part, on the electronic search capabilities of the Corrective Action Program database. Although the applicant stated that it reviewed site-specific CRs only for a minimum of 5 years, the staff noted that this timeframe bounded the performance of the ESRR program reviews. As described in Section 2.1.1 of the LRA, the ESRRs assess the conformance of the plant design, testing, maintenance, operation, and configuration with the licensing and design-basis requirements. During the ESRR program, the applicant entered identified technical issues into the Corrective Action Program database. The NRC staff previously inspected the implementation of the ESRR and concluded that, overall, the applicant effectively implemented the program (see NRC Inspection Report Nos. 50-315 and 50-316/1999-02, /1999-03, and /1999-07). Additionally, in reviewing the results of the condition report reviews conducted by the applicant, the staff noted that, in many instances, CRs dating beyond the minimum 5-year timeframe were identified. The staff also conducted an independent review of LERs from CNP and verified that information contained in previous CNP LERs did not invalidate the applicant's conclusions with regard to site-specific failures of gas systems. On this basis, the staff concluded that the applicant adequately considered site-specific and industry operating experience in its determination that there have been no failures of air/gas systems that adversely affected the safety-related SSCs. Therefore, the staff concluded that it was appropriate for the applicant to exclude nonsafety related gas-filled systems form the scope of license renewal.

Physical Impact

The applicant considered physical impact between nonsafety related equipment and safety related SSCs as a credible means for adverse spatial interactions. This category concerns the potential spatial interaction of nonsafety-related SSCs falling on, or otherwise physically impacting, safety related SSCs such that their safety functions may not be accomplished. As described in LRP-PG-14, Section 5.2.1, "Physical Impact," the applicant included all nonsafety related supports for nonseismic or seismic II/I piping systems with a potential for spatial interaction with safety-related SSCs within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). In addition, LRP-MAMR-35, Section 2.2.1, "Physical Impact," also notes that electrical conduit and cable trays with a potential for spatial interaction with safety related SCs are also considered within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). However, the applicant stated that, based on earthquake experience data, no experience exists of welded steel pipe segments falling from a strong motion earthquake and that falling of piping segments is extremely rare and only occurs when there is a failure of the supports. Therefore, the applicant concluded that, as long as the effects of aging on the supports for these piping systems are managed, it did not consider falling of piping sections credible, and the piping section itself would not be within scope for 10 CFR 54.4(a)(2) because of the physical impact hazard. However, the applicant noted in LRP-PG-14 that the effects of spray and leakage must be considered before concluding that the associated piping section could be eliminated from scope. Because the applicant considered other types of spatial interactions in addition to falling, such as leakage and spray, before determining that nonsafety related piping could be eliminated from the scope under 10 CFR 54.4(a)(2), the staff determined that this approach is consistent with the SRP-LR and staff expectations contained in the staff's December 3, 2001 and March 15, 2002 letters.

The applicant also considered physical impact caused by a load drop from an overhead handling system or missiles. The applicant considered overhead-handling systems from which a load drop could prevent the accomplishment of a safety related intended function to be within the scope of license renewal and subject to an AMR. Additionally, the applicant considered inherent nonsafety related features that protect safety-related equipment from missiles from either internal or external events to be within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) and subject to an AMR. The staff determined that the applicant considered an adequate range of falling and physical impact spatial interactions during its 10 CFR 54.4(a)(2) scoping evaluations.

Pipe Whip, Jet Impingement, or Harsh Environments

As described in LRP-PG-14, Section 5.2.2, "Pipe Whip, Jet Impingement, or Harsh Environments," the applicant considered that the spatial interactions of pipe whip, jet impingement, and harsh environments are credible only for high-energy systems. In LRP-PG-14, Section 5.2.2, the applicant states that a high-energy system operating at a temperature and pressure of greater than 93 °C (200 °F) and 275 psi, containing piping with a diameter of 1 inch or less, is excluded from consideration. The staff determined that this definition of high-energy piping and identification of credible spatial interactions is consistent with UFSAR Sections 14.4.2.1, "High Energy Systems Definition," and 14.4.2.6, "Pipe Rupture Locations and Evaluation." LRP-PG-14, Section 5.2.2 states that if a HELB analysis assumes that a nonsafety related piping system does not fail or assumes failure only at specific locations, then that piping system must be within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) and subject to an AMR to provide reasonable assurance that those assumptions remain valid through the period of extended operation. Additionally, LRP-PG-14 states that if required safety-related equipment is not protected from the effects of a HELB, then the high-energy piping is within the scope of license renewal and subject to AMR.

The March 15, 2002 letter regarding 10 CFR 54.4(a)(2) scoping describes the staff position for scoping of high-energy piping systems. This letter notes that an applicant may use mitigative and/or preventive approaches to scoping nonsafety related high-energy piping systems. If a mitigative approach is used, the applicant should demonstrate that the plant's mitigative features are adequate to protect safety related SSCs from nonsafety related SSC failures, regardless of failure location. If an applicant cannot demonstrate that the mitigative features are adequate to protect safety related SSCs from the consequences of nonsafety related SSC failures, then the entire nonsafety related SSC must be brought into the scope of license renewal. The staff determined that the applicant's approach to scoping high-energy systems is consistent with the staff position stated in the March 15, 2002 letter. Specifically, the staff concluded that the applicant applied a preventive approach and appropriately scoped high-energy piping, the failure of which could prevent the satisfactory accomplishment of a safety related intended function, in a manner consistent with the CLB.

<u>Conclusion</u>. To provide additional assurance that the applicant adequately implemented their nonsafety related scoping methodology, the NRC methodology staff reviewed a sample of the license renewal scoping results for ice condenser, auxiliary feedwater, emergency core cooling, and main feedwater systems. The staff concluded that the applicant adequately implemented

the 10 CFR 54.4(a)(2) scoping process. Additionally, the staff determined that the applicant identified and used pertinent engineering and licensing information to support the scoping determinations for the items sampled.

On the above basis, the applicant's methodology for scoping nonsafety related equipment under 10 CFR 54.4(a)(2) adequately identified those nonsafety related SSCs whose failures are considered in the CLB and could prevent the satisfactory accomplishment of the safety related functions identified under 10 CFR 54.4(a)(1). Therefore, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(2) was adequate.

Application of the Scoping Criteria in 10 CFR 54.4(a)(3). As required by 10 CFR 54.4(a)(3), the applicant must consider all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for FP (10 CFR 50.48), EQ (10 CFR 50.49), PTS (10 CFR 50.61), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) to be within the scope of the license renewal. Section 2.1.3.1.3, "Regulated Events," of the SRP-LR states that all SSCs that are relied upon in the plant's CLB (as defined in 10 CFR 54.3), plant-specific operating experience, industrywide operating experience (as appropriate), and safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations under 10 CFR 54.4(a)(3) must be included within the scope of the Rule. However, consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB, and that have not been previously experienced, is not required.

The staff reviewed the applicant's approach to identifying SSCs relied upon to perform a function related to the five regulated events described in 10 CFR 54.4(a)(3). As part of this review, the staff discussed the methodology with the applicant's LRA team, evaluated the documentation developed to support the review, and evaluated a sample of the resultant SSCs identified as within scope for the 10 CFR 54.4(a)(3) criterion.

The applicant documented the methodology for performing the scoping of SSCs in accordance with 10 CFR 54.4(a)(3) in implementation procedures LRP-PG-01, Revision 5, "Scoping Systems and Structures," and LRP-PG-06, Revision 1, "License Renewal Topical Reports." A series of individual topical reports for ATWS, PTS, SBO, FP, and EQ (Topical Report for License Renewal Scoping LRP-TR-01 through LRP-TR-05, respectively) documents the results of the applicant's review for each regulated event.

The applicant developed the set of topical reports LRP-TR-01 through LRP-TR-05 to collect the CLB information pertaining to each regulated event and to identify specific SSCs relied upon in the CLB to perform an intended function for those specific regulated events. To help ensure development of a consistent and comprehensive set of reports, the applicant initially developed implementation guideline LRP-PG-06, which contains format and content requirements for topical report generation. Project guideline LRP-PG-06 contains detailed information on the initiation of a topical report, preparation steps, review and approval procedures, and process for topical report revision. In addition, the guideline provides useful tables of potential CLB source documentation, as well as final report format requirements. The staff found the LRP-PG-06 guideline to be detailed and useful for review of the topical reports.

The staff also reviewed the set of topical reports for each regulated event. Each report contains a detailed description of the history of the specific regulated event, a chronology of the plant-specific design and licensing basis related to the regulation, and a description of the various systems and structures and their specific intended functions associated with and credited for the pertinent regulated event. The reports also identify the CLB source information, which is retained in a retrievable format to allow for reviewing specific results associated with individual systems and structures. The applicant identified these sources primarily through the use of the plant's electronic documentation program, "Folio," which contains the regulations, plant-specific design calculations, UFSAR, licensing correspondence, design change information, generic communications, and industry operating experience reports. The applicant's license renewal project team developed the reports, which were reviewed by a subject matter expert, LRA management, and independent contractors.

The staff also reviewed the applicant's specific actions to address the ISG pertaining to SBO. In a letter from D. Matthews (NRC) to A. Nelson and D. Lochbaum dated April 1, 2002, the staff provides additional guidance for scoping of equipment relied on to meet the requirements of the SBO rule. This staff guidance, identified as ISG-2, "Scoping of Equipment Relied Upon to Meet the Requirements of the Station Blackout (SBO) Rule for License Renewal," states that the staff determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of license renewal. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. In Section 2.1.3 of the LRA, the applicant stated that scoping is in accordance with ISG-2. Additionally, Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Control Systems," of the LRA, states that the offsite power system is included in the scope of license renewal. The LRA further states that the offsite power system provides the electrical interconnections between the offsite network and the station auxiliary buses, as well as electrical interconnections among other buildings and facilities located on the CNP site. Based on the applicant's consideration of the offsite power system during SBO scoping evaluations, the staff determined that the applicant's scoping methodology adequately addresses ISG-2. Section 2.5 of this SER further discusses the staff's assessment of the actual electrical power scoping results.

Conclusion

As part of the review of the applicant's scoping methodology, the staff reviewed a sample of the license renewal database's 10 CFR 54.4(a)(3) scoping results to assess the adequacy of the applicant's scoping methodology. The staff verified that the applicant's scoping methodology identified and used pertinent engineering and licensing information to determine the SSCs required to be within scope in accordance with the 10 CFR 54.4(a)(3) criteria and verified that the applicant's LRA staff was cognizant of the requirements for evaluating and documenting the review. On the basis of its review, the staff concludes that the applicant adequately defined and implemented a methodology for identifying systems and structures to meet the scoping criteria of 10 CFR 54.4(a)(3).

2.1.3.1.3 Plant Level Scoping of Systems and Structures

Section 5.4 of LRP-PG-01 describes the applicant's methodology for performing the scoping of systems and structures. The applicant identified each system or structure within the scope of license renewal as follows:

- The applicant selected a system or structure from a list of plant systems based on system codes contained in the FDB. Procedure 12-EHP-5043-FDB-001, Section 4.7, "Approved Plant System Codes," identifies the FDB as the primary repository for approved plant system codes to be used at the CNP.

- The applicant obtained the information on the selected system or structure from a review of CLB and related documents.

- Based on the CLB information, the applicant identified mechanical system or structural level functions. The applicant documented the license renewal intended functions by completing a system function scoping table for each mechanical system or structure function. The staff determined that the nine scoping questions included on the system function scoping table were consistent with each of the scoping criteria of 10 CFR 54.4(a).

- Project guideline LRP-PG-01, Section 5.5, "System Boundary Details," states that boundaries are determined by mapping the pressure boundary associated with the license renewal intended functions onto the system flow diagrams. All the equipment and piping shown on the drawings is initially assumed to be part of the system. Flow diagrams, one-line drawings, civil/structural drawings, and text description provide system boundaries, as appropriate.

- To facilitate the scoping and screening process and the AMRs, the applicant realigned certain components from its FDB parent system to another system. Project guideline LRP-PR-01, Section 2.0, "Methodology," states that system boundaries are established in terms of the major intended functions they perform. This permitted the AMRs of some UFSAR-described systems or portions of systems to be combined with other system reviews, which allows clearer alignment to the systems described in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued July 2001. The applicant stated that individual system/structure scoping reports (ISSRs) describe the boundaries of the system with references to applicable boundary drawings, including the effects of any system combinations established for the review. Component realignment is intended to allow components to be evaluated as a coherent functional group within an appropriate system or commodity group. The implementation procedure includes documentation requirements to permit traceability of components that realign from one parent system to a different license renewal system.

- The associated ISSR documents the results of system and component level scoping. The ISSR includes a system description, a system boundary evaluation, information about interfacing systems, identification of system or structure functions, the completed system function scoping question table, and associated references. The applicant established guidance for the preparation of ISSRs in LRP-PG-01, Section 5.7, "Review and Approval of ISSRs," which provides guidance for the review and approval of ISSRs.

All ISSRs require engineering manager approval. Additionally, senior reactor operator and system manager reviews are required for certain systems or structure ISSRs. The applicant summarized the system and structure scoping process and the results of the identification of systems and structures that are within the scope of license renewal in LRP-PR-01, "Final System and Structure Scoping Report."

During the scoping methodology audit, the staff reviewed a sampling of ISSRs and concluded that the applicant's scoping reports contained an appropriate level of detail to document the scoping process. In particular, the ISSRs and the final system and structure scoping report contain sufficient detail to permit the identification of system and structure intended functions and scoping evaluation boundaries. Additionally, during the scoping and screening methodology audit, the staff reviewed the implementation of the component realignment guidance and determined that the realignment process did not adversely impact component-level scoping and screening.

Conclusion

Based on a review of the LRA, the scoping and screening implementation procedures, and a sampling review of system and structure scoping results during the methodology audit, the staff concluded that the applicant's scoping methodology for systems and structures is adequate. Specifically, the staff determined that the applicant's methodology reasonably identifies systems and structures within the scope of license renewal and their associated intended functions.

2.1.3.1.4 Component Level Scoping

The applicant considered scoping to be the process of identifying systems and structures that perform a license renewal intended function. The licensee did not describe a component level scoping process in the LRA, but instead indicated that it performed component-level scoping as an integral part of the screening process. However, as described in Section 5.5 of LRP-PG-01, the components within a system are scoped during the screening phase (not the scoping phase). Framatome/Entergy, the applicant's primary contractor for license renewal, performed the component level scoping and screening phase. Using the ISSRs prepared by the applicant and CLB information sources, Framatome/Entergy performed component level scoping and screening evaluations. Framatome/Entergy used approved license renewal project procedures to perform detailed component level evaluations. The AMRRs and marked system flow diagrams document the results of the component level scoping and screening evaluations. The applicant's administrative controls for the license renewal project include procedures for the owner acceptance review of license renewal documents prepared by contractor personnel. Therefore, although Framatome/Entergy prepared the AMRRs, the applicant's license renewal project team members and engineering manager are responsible for their review and approval. The scope of the owner acceptance review includes verification that all system level intended functions are included, the correlation between scoping drawings and intended functions, and a review of scoping results for major components.

Although the applicant considered component level scoping as part of the screening process, the staff evaluated the methodology the applicant used to identify components necessary to support system and structural level intended functions. After the applicant identified systems and structures within the scope of licensee renewal and their associated intended functions, the applicant performed a review to identify the components of each in-scope system and structure that supports an intended function. As described in Section 2.1.1 of the LRA, a component is determined to be in-scope if it is safety related, pursuant to 10 CFR 54.4(a)(1), is needed to fulfill a system intended function, pursuant to 10 CFR 54.4(a)(2), or is needed to demonstrate compliance with a regulated event. The following sections describe the staff review of the methodology to scope mechanical, structural, and electrical components.

Mechanical Component Scoping. Project guideline LRP-PG-04 provides the applicant's proceduralized guidance for scoping mechanical system components. Section 5.1, "Screening of Components," of LRP-PG-04, states that, for each mechanical system within the scope of license renewal, the screening process will identify those components that are subject to an AMR. Component level scoping and screening evaluations consist of the following major activities:

- The applicant identified the system evaluation boundary by indicating those portions of the system that are necessary to ensure that the intended functions of the system will be performed. It used the information contained in the ISSRs as the primary basis for determining the evaluation boundary. Project guideline LRP-PG-04 requires that this identification of evaluation boundaries be based on the CLB, plant-specific experience, industrywide operating experience as appropriate, and existing design-basis documentation.

- The applicant also identified components subject to an AMR. Within the evaluation boundary, long-lived passive components that perform or support an intended function without moving parts or a change in configuration or properties are subject to an AMR. In accordance with the scoping and screening methodology, the applicant performed component level scoping and screening during this portion of the methodology. In LRP-PR-04, Section 5.1.2 states that long-lived, passive components within the evaluation boundary are subject to an AMR.

- Finally, the applicant documented component intended functions. Procedure LRP-PG-04, Section 5.1.2, states that passive, long-lived components within the evaluation boundary should be documented in the associated AMRR. Additionally, the AMRR includes a summary statement of the component level intended functions. The component intended function is the specific simple function, such as "maintain pressure boundary," that supports the broader system intended function.

RAI 2.1-5

In general, the staff concluded that the applicant's methodology adequately scopes mechanical components that support a system level intended function. However, during the audit, the applicant could not adequately describe the evaluation that it performed to determine if any insulation installed in the plant is required to support any system intended functions identified during the scoping process. As a result, the staff requested in RAI 2.1-5 that the applicant describe any intended functions performed by insulation or the basis for determining that insulation (*i.e.*, piping insulation) does not meet the scoping criteria described in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3).

The applicant responded to RAI 2.1-5 by letter dated May 7, 2004. The applicant stated that, in some internal plant locations, piping insulation serves the intended function of limiting heat loss to reduce area heat loads during an accident. The applicant noted that insulation that performs an intended function at the CNP site is located indoors and protected from the weather. The applicant also indicated that, based on site-specific operating experience, indoor insulation at CNP has no aging effects requiring management (AERMs).

In reviewing the applicant's response, the staff concluded that piping insulation performs an intended function at the CNP site. However, the applicant did not identify piping insulation as either a component or commodity type within the scope of license renewal. Because insulation performs its intended function without moving parts or without a change in configuration or properties and is generally not subject to periodic replacement, insulation within the scope of license renewal should be subject to an AMR in accordance with the requirements of 10 CFR 54.21. Although the applicant noted that it reviewed plant-specific operating experience to identify aging-related degradation mechanisms for insulation, the staff concluded that this information pertained more to the AMR than to the scoping evaluation. Furthermore, in accordance with staff guidance issued for 10 CFR 54.4(a)(2) scoping evaluations, exclusion of SSCs from the scope based on a review of site-specific and industry operating experience applies only to the identification of noncredible failures of nonsafety related scoping pursuant to 10 CFR 54.4(a)(2). Additionally, the staff could not determine whether the applicant had considered industry operating experience or potential insulation intended functions in accordance with the 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3) scoping criteria. Therefore, the staff lacked sufficient information to conclude that the applicant's scoping methodology adequately considered the intended functions performed by piping and component insulation.

On May 17, 2004, and May 21, 2004, the staff held conference calls with the applicant to discuss the RAI and to further clarify the staff's requested information. As a result of those conference calls, the applicant provided a supplemental response to RAI 2.1-5 in a letter dated August 11, 2004. The applicant's response stated that in some internal plant locations, including portions of piping in the engineered safety features (ESF) systems (emergency core cooling, and auxiliary feedwater), piping insulation performed an intended function, and is therefore in scope for license renewal. The applicant performed an AMR of the system piping effected.

On the basis of the information provided by the applicant, which included (1) a discussion of the relevant systems with insulation that perform an intended function, (2) inclusion of that insulation within scope of license renewal, and (3) performance of an AMR of the insulation, the staff concludes that the applicant provided an adequate basis for the evaluation and determination of insulation within the scope of license renewal. On the above basis, RAI 2.1-5 is resolved.

Conclusion. The staff reviewed a sampling of scoping results for the ice condenser, auxiliary feedwater, emergency core cooling, and main feedwater systems during the scoping and screening methodology audit to verify that the applicant's proceduralized methodology was adequately implemented. For the samples reviewed, the staff determined that the applicant effectively implemented the scoping methodology. Additionally, the applicant adequately documented and justified the results of the component level scoping process.

The staff determined that the applicant's proceduralized methodology is consistent with the description provided in LRA and the guidance contained in the SRP-LR, Section 2.1, and was adequately implemented. Based on a review of the applicant's detailed scoping implementation procedures, and a sampling review of mechanical components scoping results, the staff concluded that the applicant's methodology for identifying mechanical components within the scope of license renewal meets the requirements of 10 CFR 54.4(a).

Structural Component Scoping. Implementation procedure LRP-PG-03 provides guidance for the scoping and screening of structural components. Procedure LRP-PG-03 includes the following steps for structural component scoping:

- Identification of structural components—For each structure within the scope of license renewal, the applicant evaluated the structure's structural components and commodities to determine those subject to an AMR. As part of the screening process for structural components and commodities, the applicant reviewed DBDs (*i.e.*, UFSAR, drawings, and specifications) to identify specific structural components and commodities that make up the structure. The applicant noted that structural components and commodities often have no unique identifiers such as those given to mechanical components. Therefore, the applicant grouped structural components and commodities based on materials of construction as a means of categorizing them for AMRs.

- Identification of structural component and commodity groups—The applicant categorized structural components and commodities by the materials of construction. LRP-PG-03 stated that a review of DBDs (*i.e.*, UFSAR, drawings, and specifications) is required to determine specific material types for structural components and commodities.

- Identification and documentation of structural component intended function—The applicant also evaluated structural components and commodities to determine intended functions as they relate to the license renewal process. Procedure LRP-PG-03 refers to the intended function guidance in NEI 95-10 and provides a listing of structural intended functions to be used during scoping. LRP-PG-03 also states that the applicant should document structural components and commodities applicable to a particular structure, in addition to the associated intended functions, in the AMRR.

The staff concluded that the applicant's methodology for scoping structural components provides reasonable assurance that structural components would be appropriately scoped in accordance with 10 CFR 54.4(a). The staff reviewed the applicant's list of structural intended functions provided in LRP-PG-03 and determined that the applicant considered all the structural intended functions in SRP-LR, Table 2.1-4, "Typical Passive Structure and Component Intended Functions."

Conclusion. The staff determined that the applicant's proceduralized methodology is consistent with the description provided in Section 2.1.2.2 of the LRA and the guidance contained in the SRP-LR, Section 2.1. Based on review of information contained in the LRA, the applicant's detailed scoping implementation procedures, and a sampling review of structural component scoping results, the staff concludes that the applicant's methodology for the identification of structural components within the scope of license renewal meets the requirements of 10 CFR 54.4(a).

Electrical and I&C Component Scoping. Section 2.5.3.1, "Components Within the Scope of License Renewal, of the SRP-LR, states that an applicant may use the plant spaces approach in scoping electrical and I&C components. In the plant spaces approach, an applicant may indicate that all electrical and I&C components located within a particular area are either within or not within the scope of license renewal. SRP-LR, Table 2.5-1, "Examples of 'Plant Spaces' Approach for Electrical and I&C Scoping and Corresponding Review Procedures," provides guidance for the review of scoping performed in accordance with the plant spaces approach. In particular, if the applicant limits the scope of electrical and I&C components considered within the scope of license renewal by excluding components in certain plant spaces, SRP-LR, Table 2.5-1, indicates that this approach should not result in failing to place electrical and I&C components that perform intended functions within the scope of license renewal.

Implementation procedure LRP-PG-05, "Electrical System Scoping, Screening and Aging Management Reviews," and topical report LRP-TR-06, "Methodology for Assigning Electrical Component Commodity Groups," provide guidance for the scoping and screening of electrical components. Procedure LRP-PG-05 discusses the activities associated with the electrical component scoping, as well as screening information and aging management report information. Topical report LRP-TR-06, provides detailed information on electrical component and commodity type designations and is based primarily on industry guidance embodied in NEI 95-10 and the Electric Power Research Institute (EPRI) License Renewal Electrical Handbook.

For the license renewal evaluation, initial plant-specific electrical component types are identified from several information sources, including the plant equipment database, electrical system and raceway drawing and information, and field evaluations. The applicant used the results of this initial review to develop a comprehensive list of plant-specific electrical commodity groups, consistent with the guidance in Appendix B to NEI-95-10, which encompasses all of the types of electrical components identified through the application of the spaces approach. The applicant further evaluated the resultant commodity groups to identify those that are passive, in accordance with the 10 CFR Part 54.21(a)(1)(i) criterion. As a result, two commodity groups, (1) cables and connectors, bus, electrical portions of electrical and I&C penetration assemblies, and (2) high-voltage insulators, were identified as passive. The applicant evaluated these two commodity groups further and subdivided them into seven subcategories, consistent with the guidance in Appendix B to NEI-95-10. Section 2.1.3.2.3 of this SER further discusses these subcategories. The applicant documented the results of its evaluation in LRP-EAMR-01, "Aging Management Review for Electrical Systems."

The staff reviewed the samples of the source information the applicant used to identify electrical components and commodity groups, reviewed the process with cognizant members of the applicant's LRA team, and reviewed a sample of the component and commodity types resulting from the applicant's review effort. On the basis of these reviews, the staff concludes that the applicant's implementation of the electrical spaces approach provides reasonable assurance that electrical and I&C components that perform intended functions are within the scope of license renewal.

Additionally, the staff reviewed the applicant's evaluation of fuse holders to assure that it adequately considered the staff's guidance in ISG-5, "The Identification and Treatment of Electrical Fuse Holders for License Renewal." Specifically, in a letter from D. Matthews (NRC) to A. Nelson and D. Lochbaum, dated March 10, 2003 which transmits ISG-5, the staff provides additional guidance for scoping of electrical fuse holders. In that ISG, the staff concludes that fuse holders are passive, long-lived electrical components within the scope of license renewal and subject to an AMR. However, the staff notes that fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power invertors, battery chargers, and circuit boards, are considered to be piece parts of the larger assembly and outside the scope for license renewal. In LRA Section 2.1.3, the applicant stated that it will evaluate fuse holders meeting the requirements of ISG-5 before the beginning of the period of extended operation for possible AERMs. This is Commitment #32 in Appendix A of this SER. Furthermore, the licensee stated in the LRA that it will either replace these fuse holders, modify them to remove the aging effects, or implement a program to manage the aging effects. This approach is consistent with LRA Table 2.1.1, "Standard List of Passive Electrical Commodities," which includes fuse blocks in the list of passive electrical commodities subject to an AMR. The staff concluded that, although the applicant has not identified specific fuse holders that are within scope, the applicant included fuse holders in scope as an electrical commodity. Because the applicant used a spaces approach for electrical scoping, the staff concludes that the inclusion of fuse holders that are not part of a larger assembly as a commodity group meets the ISG-5 guidance for scoping of fuse holders.

Conclusion. The staff reviewed the samples of the source information used by the applicant to identify electrical components and commodity groups, reviewed the process with cognizant members of the applicants LRA team, and reviewed a sample of the component and commodity types resulting from the applicant's review effort. On the basis of these reviews, the staff determined that the implementation of the electrical spaces method for scoping of electrical and I&C components is consistent with the guidance contained in the SRP-LR. Because the applicant's use of the electrical spaces approach integrates the scoping and screening phases of the methodology, Section 2.1.3.2.3 of this SER discusses additional conclusions regarding the use of this method.

2.1.3.2 Screening Methodology

The staff reviewed the screening methodology used by the applicant to determine whether mechanical, structural, and electrical components within the scope of license renewal would be subject to further aging management evaluation. The applicant described its screening process in Section 2.1.2 of the LRA. In general, the applicant's screening approach consists of evaluations to determine which SCs that support an intended function are passive and long-lived. Passive, long-lived SCs are then subject to further AMR.

The staff evaluated the applicant's screening methodology against the criteria contained in 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2) using the review guidance in the SRP-LR, Section 2.1.3.2, "Screening." 10 CFR 54.21(a)(1) states that the applicant's IPA must identify and list those SCs subject to an AMR. Further, 10 CFR 54.21(a)(1) requires that SCs subject to an AMR encompass those SCs that (1) perform an intended function, as described in 10 CFR 54.4, without moving parts or a change in configuration or properties, and (2) are not subject to replacement based on a qualified life or specified time period. Pursuant to 10 CFR 54.21(a)(2), the applicant must describe and justify the methods used to meet the requirements of 10 CFR 54.21(a)(1). In the LRA, the applicant described screening methodologies that are unique to the mechanical, structural, and electrical disciplines. The following describes the staff evaluation of the applicant's screening approach for each of these disciplines.

2.1.3.2.1 Mechanical Component Screening

The applicant provided procedural guidance for the conduct of mechanical component screening in LRP-PG-04, Section 5.1.2, "Identifying Components Subject to Aging Management Review." This section states that, within the evaluation boundary, long-lived passive components that perform or support an intended function without moving parts or a change in configuration or properties are subject to an AMR. The applicant defined the evaluation boundary for mechanical systems to include those portions of a system that are necessary to ensure that the intended functions of the system will be performed. Additionally, if the component is not subject to replacement based on a qualified life or specified time period, then, in accordance with procedure LRP-PG-04, the applicant considered the component long-lived. The applicant did not include components that are not long-lived in the AMR. The applicant noted that components subject to refurbishment or replacement solely on the basis of condition monitoring (*i.e.*, the component is replaced only if leakage is observed during a routine walkdown) would be considered long-lived and require an AMR.

The applicant grouped components into commodity groups, where possible, to allow disposition of the entire group with a single AMR. The applicant stated that the grouping of components is based on characteristics such as similar design, similar materials of construction, similar aging management practices, and similar environments.

In a May 1, 2002 letter from P.T. Kuo (NRC) to A. Nelson and D. Lochbaum, the staff provided guidance on the identification and treatment of housings for active components for license renewal scoping and screening. As discussed in this letter, the staff expects applicants for license renewal to identify active component housings (*i.e.*, housings for fans, dampers, and heating and cooling coils) which require an AMR. This determination should consider whether failure of the housing would result in a failure of the associated active component to perform its function, and whether the housing meets the long-lived and passive criteria defined in 10 CFR Part 54. In Section 2.1.3, "Interim Staff Guidance Discussion," of the LRA, the applicant stated that the process used to identify passive components subject to an AMR identifies active component housings (*i.e.*, pump casings, valve bodies, and housings for fans and dampers) which are subject to AMR. In addition, the staff notes that LRA Table 2.3.3-6, "Heating, Ventilation and Air Conditioning Systems Components Subject to Aging Management Review," includes damper housings, fan housings, and filter housings as long-lived passive components that provide a pressure boundary component level intended function. Based on the above, the staff concludes that the applicant adequately addressed the interim guidance for housings of active components described in the May 1, 2002 letter.

RAI 2.1-4

The applicant described the screening review for certain types of consumable commodities in Section 2.1.2.4.1, "Packing, Gaskets, Component Seals, and O-Rings," of the LRA, which states that packing, gaskets, component seals, and O-rings are not subject to condition or performance monitoring which could demonstrate that specific criteria are met. During the methodology audit and review of the applicant's screening methodology procedures, the staff lacked sufficient information to determine what specific methods and criteria the applicant used to determine that these consumables are not subject to an AMR. SRP-LR, Table 2.1-3, "Specific Staff Guidance on Screening," provides guidance for determining if consumable items should be subject to an AMR. For consumables that are periodically replaced, SRP-LR,

Table 2.1-3, states that the applicant should identify the standards that it relied on for replacement as part of the methodology description. For consumables such as packing, gaskets, component seals, and O-rings, Table 2.1-3 states that these components may be excluded from an AMR only upon demonstrating a clear basis. Therefore, in RAI 2.1-4, the staff requested the applicant to clarify the basis used to exclude consumables from further AMR.

In its May 7, 2004, response to RAI 2.1-4, the applicant stated that the two criteria discussed in LRA Section 2.1.2.4.1 are (1) sealing materials that are short-lived because they are replaced on a fixed frequency or have a qualified life, and (2) sealing materials not relied on to maintain leakage below limits and not relied on to maintain system pressure high enough to deliver required flows. The applicant stated that sealing materials that are considered short-lived include: (1) electrical component sealing materials with a qualified EQ life; (2) reactor vessel O-rings that are periodically replaced; and (3) reactor coolant pump (RCP) seals that are periodically monitored and replaced as needed. The applicant noted that the RCP seals are a highly visible and closely monitored element of the RCS. Further, the applicant has site-specific procedures specifying performance monitoring and inspection activities of these seals and subsequent seal replacement based on the results of these activities. In addition to these commodities, the applicant also determined that pressurizer manway gaskets do not require an AMR because they are not required to maintain pressure boundary integrity. The applicant concluded that packing, gaskets, component seals, and O-rings that are not considered pressure boundaries per American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, do not require an AMR. Because the staff determined that the applicant provided a clear basis for its treatment of packing, gasket, component seals and O-rings, RAI 2.1-4 is resolved.

The staff determined that the applicant's screening criteria are consistent with the requirements of 10 CFR 54.21 and are therefore acceptable. In particular, the screening process provides reasonable assurance that passive, long-lived mechanical components within the scope of license renewal would be subject to an AMR.

Conclusion

Based on the above, the staff determined that the applicant's mechanical screening methodology is consistent with the guidance contained in the SRP-LR and is capable of identifying passive, long-lived components within the scope of license renewal that are subject to an AMR.

2.1.3.2.2 Structural Component Screening

The applicant described its screening approach for structural components in procedure LRP-PG-03. For each structure within the scope of license renewal, LRP-PG-03 states that it is necessary to evaluate the structure's structural components and commodities to determine those subject to an AMR. The procedure also states that the screening process involves a review of design-basis information to identify the specific structural components and commodities that make up the structure. Section 5.1, "Screening of Structural Components and Commodities," of LRP-PG-03, states that structural components or commodities subject to an AMR are those that perform an intended function without moving parts or a change in configuration or properties and are not subject to replacement based on qualified life or specified time period. The applicant noted that since structures are inherently passive, and, with few exceptions, are long-lived, the screening of structural components and commodities is based primarily on whether they perform an intended function. The applicant noted that structural components and commodities often have no unique identifier. Therefore, the applicant grouped structural components and commodities based on materials of construction. The applicant identified these structural component groups in the associated AMR.

The staff determined that the applicant's screening criteria are consistent with the requirements of 10 CFR 54.21 and are, therefore, acceptable. In particular, the screening process provides reasonable assurance that passive, long-lived structural components within the scope of license renewal would be subject to an AMR.

Conclusion

The staff determined that the applicant's structural component screening methodology is consistent with the guidance contained in the SRP-LR and is capable of identifying those passive, long-lived components within the scope of license renewal that are subject to an AMR.

2.1.3.2.3 Electrical and I&C Component Screening

The applicant described its screening approach for electrical components in procedure LRP-PG-05. Procedure LRP-PG-05 states that it is not necessary to evaluate each electrical systems within the plant to identify individual system intended functions. Rather, the applicant implemented the spaces approach to identify all electrical component types and commodities within the electrical systems of the plant to determine those subject to an AMR. Section 5.0, "Instructions," of LRP-PG-05, discusses the use of the EPRI License Renewal Electrical Handbook as a basis for identifying and classifying plant-specific electrical components into commodity groups consistent with the guidance in NEI 95-10. Section 5.1, "Scoping Considerations," of LRP-PG-05, identifies seven electrical commodity groups that potentially require AMRs. The applicant identified these electrical commodity groups in the associated AMRR. These seven categories include insulated cables and connectors (including fuse holders), electrical portions of penetration assemblies, phase bus, transmission conductors, switchyard bus, high-voltage insulators, and uninsulated ground conductors. The applicant then evaluated these commodity groupings to identify whether they are long-lived or subject to replacement based on a qualified life or specified time period. The only electrical commodities that meet the long-lived criterion are specifically identified as included within the Environmental Qualification Program. All other components within these seven commodity groups are included in subsequent AMRs.

The staff determined that the applicant's screening criteria are consistent with the requirements of 10 CFR 54.21 and are, therefore, acceptable. In particular, the screening process provides reasonable assurance that passive, long-lived electrical component and commodity groups within the scope of license renewal would be subject to an AMR.

Conclusion

The staff determined that the applicant's electrical and I&C screening methodology is consistent with the guidance contained in the SRP-LR and is capable of identifying passive, long-lived components within the scope of license renewal that are subject to an AMR.

2.1.4 Evaluation Findings

The staff review of the information presented in Section 2.1 of the LRA, the supporting information in the scoping and screening implementation procedures and reports, the information presented during the scoping and screening methodology audit, and the applicant's responses to the staff's RAIs form 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 nonsafety-related piping segments and associated components into the scope of license renewal, is consistent with the requirements of 10 CFR Part 54 and the staff's position on the treatment of nonsafety-related SSCs. On the basis of this review, the staff concludes that there is reasonable assurance 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

In LRA Section 2.2, "Plant-Level Scoping Results," the applicant provided the results of its scoping review. The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the applicant properly identified all plant level systems and structures that are within the scope of license renewal as required by 10 CFR 54.4.

2.2.1 Summary of Technical Information in the Application

The applicant first identified all plant systems and structures by using multiple sources of documentation, including CLB references, the FDB, piping and instrumentation drawings (P&IDs), and civil/structural plant layout drawings. The applicant then evaluated the identified systems and structures against the criteria of 10 CFR 54.4(a). The applicant listed the systems and structures that are within the scope of license renewal.

Tables 2.2-1a, 2.2-1b, and 2.2-3, of the LRA document the plant-level scoping results for mechanical systems, electrical systems, and structures, respectively, that are within the scope of license renewal. The applicant identified 47 mechanical systems, 45 electrical systems, and 18 structures within the scope of license renewal. Table 2.2-2 of the LRA identifies 20 mechanical systems that are not within the scope of license renewal. Table 2.2-4 of the LRA identifies 43 structures or buildings that are not within the scope of license renewal. The applicant did not exclude any electrical systems from the scope of license renewal.

2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.2, the contents of the CNP UFSAR, and the information provided in the applicant's responses to the staff's RAIs to determine whether it excluded any systems and structures required to perform intended functions from the scope of license renewal. The staff conducted its review in accordance with Section 2.2 of the SRP-LR.

The staff's review of LRA Section 2.2 identified areas in which it needed additional information to complete its evaluation of the applicant's plant-level scoping results. Therefore, the staff issued RAIs to the applicant concerning specific issues to determine whether the applicant has properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following describes the staff's RAIs and the applicant's responses.

RAI 2.2-1

With respect to the scoping methodology, LRA Section 2.1.1 states the following:

> Consistent with NEI 95-10, the scoping process used for the CNP license renewal project began with a list of plant systems and structures, determined the functions they perform, and then determined which functions met any of the three criteria of 10 CFR 54.4(a). Functions that meet any of the criteria are intended functions for license renewal, and the systems and structures that perform these functions are included within the scope of license renewal.

For the staff to determine that the applicant did not omit any SSCs that should be within the scope of license renewal according to 10 CFR 54.4(a), the staff requested that the applicant confirm whether all the SSCs in such systems and structures were included within the scope of license renewal. If not, the staff requested that the applicant describe what SSCs were excluded from the scope of license renewal.

In its response, dated January 14, 2004, the applicant stated the following:

> To provide assurance that no structures, systems, and components that should be within the scope of license renewal according to 10 CFR 54.4(a) were omitted from the CNP license renewal scope, the response to this question addresses the comprehensiveness of the CNP scoping and screening process.
>
> All of the mechanical and electrical systems at CNP were reviewed for inclusion in the scope of license renewal. Use of the CNP facility database, a comprehensive database of plant equipment, provides assurance that all systems are reviewed for inclusion in the scope of license renewal.
>
> As discussed in LRA Section 2.1.1, the scoping process began with a list of plant systems and structures. The functions performed by the plant systems and structures were determined, then a determination was made as to which functions met any of the three criteria of 10 CFR 54.4(a). Functions that meet any of the criteria are intended functions for license renewal, and the systems and structures that perform these functions are included within the scope of license renewal. These systems and structures that perform intended functions are indicated in the LRA in Table 2.2-1a, Systems Within the Scope of License Renewal Mechanical Systems, Table 2.2-1b, Systems Within the Scope of License Renewal Electrical Systems (Bounding Approach), and Table 2.2-3, Structures Within the Scope of License Renewal. Systems and structures that are not within the scope of license renewal are listed in the LRA in Table 2.2-2, Systems Not Within the Scope of License Renewal, and Table 2.2-4, Structures Not Within the Scope of License Renewal. The mechanical and electrical system codes from the CNP facility database were included in LRA Tables 2.2-1a, 2.2-1b, and 2.2-2.

To ensure comprehensive consideration of structures for inclusion in the scope of license renewal, the structures listed in LRA Tables 2.2-3 and 2.2-4 were identified from a review of current licensing basis documentation, including the Updated Final Safety Analysis Report and civil/structural plant layout drawings. The current license basis documentation was used in addition to the facility database (FDB) since all structures are not listed in the facility database.

In conclusion, all components within the systems identified in LRA Tables 2.2-1a and 2.2-1b, and all structures identified in LRA Table 2.2-3, were conservatively considered to be within the scope of license renewal for the purposes of identifying components and structures that are subject to AMR.

Based on its review of the response, the staff finds the applicant's response to RAI 2.2-1 acceptable because it clarifies the methodology used in the development of the list of SSCs, the scoping process, and the use of supporting documentation. Therefore, the staff's concerns described in RAI 2.2-1 are resolved.

RAI 2.2-3

In a comparison of the CNP units, the staff finds that, in general, the CNP LRA does not identify design differences in the systems and components for CNP, Unit 1, compared to Unit 2. The NRC licensed CNP, Units 1 and 2, approximately 3 years apart, and the units have a 5-percent difference in rated thermal power.

Therefore, in RAI 2.2-3, the staff asked the applicant to provide a general description of the major design differences between the systems and components of the two units. The staff requested that the applicant explain how it addressed these differences in the scoping and screening review process for the corresponding systems of the two units.

In its response, dated May 7, 2004, the applicant stated that the CNP units are essentially the same. The applicant reviewed any differences in accordance with the established process for scoping and screening. Sections 2 and 3 of the LRA address the differences as required. The following summarizes the differences that are considered in the LRA:

- The Unit 1 turbine generator was manufactured by the General Electric Company with an electro-hydraulic type turbine control system. The Unit 2 turbine generator was manufactured by Brown, Boveri and Company with a mechanical-hydraulic turbine control system.

- Steam generators for Unit 2 were replaced in 1988. Unit 1 steam generators were replaced in 2000.

- The Unit 1 refueling water storage tank is heated by means of heat tracing circuits. The Unit 2 refueling water storage tank is heated by means of a pump that recirculates tank water through two electric heaters.

- Reactor core at Unit 1 consists of a 15 X 15 array fuel assembly design, whereas the Unit 2 core comprises of a 17 X 17 array fuel assembly.

Based on its review, the staff finds the applicant's response to RAI 2.2-3 acceptable because the applicant adequately described the major differences between the CNP units, as well as identified differences that are considered in the LRA. Therefore, the staff's concern described in RAI 2.2-3 is resolved.

RAI 2.2-4

Section 1.4 of the CNP UFSAR notes that the design of Unit 1 preceded the adoption of the Appendix A, "General Design Criteria," to 10 CFR Part 50, and, therefore, the CNP plant is designed and constructed to meet the intent of the proposed general design criteria (GDC), dated July 11, 1967. Use of the preliminary version of the plant-specific design criteria (PSDC) may have resulted in significant differences in the licensing bases for CNP, Units 1 and 2, from later pressurized-water reactors (PWRs) of a similar design.

To facilitate its review, the staff requested that the applicant provide a summary description of the impact of these differences on the CNP design, including the technical areas in which any differences could affect the scoping and screening results for the two units.

In its response dated May 7, 2004, the applicant stated that the CNP PSDC define the principal criteria and safety objectives for the CNP design. The PSDC discussed in Section 4 of the UFSAR apply I&M's understanding of the intent of the GDC proposed by the Atomic Energy Commission (AEC) in July 1967. The CNP PSDC, as presented in the preliminary safety analysis report, were approved by reference when the AEC issued construction permits.

The applicant submitted the application for the operating license, including the final safety analysis report (FSAR), on February 1, 1971, before the May 21, 1971, effective date of Appendix A to 10 CFR Part 50. The AEC review ensured that, at a minimum, the CNP design met the PSDC by evaluating the design against the proposed GDC. Section 3.1 of the September 10, 1973, operating license SER documents this review and acknowledges that CNP is not designed to, and I&M is not committed to, the "current general design criteria," although the design meets these criteria:

> The Cook plant was designed and constructed to meet the intent of the Proposed General Design Criteria, published July 11, 1967. The Final Safety Analysis Report had been filed with the Commission when revisions of the General Design Criteria were published in February 1971 and July 7, 1971. We reviewed the plant design against the current General Design Criteria and we believe that the design meets these criteria.

The applicant performed the license renewal IPA in accordance with the requirements of 10 CFR Part 54 and consistent with the guidance provided by NEI 95-10. This review does not include a detailed comparison of the CNP design to the GDC in Appendix A to 10 CFR Part 50, but rather assesses the existing plant design, as described in the CLB, to ensure that the SCs requiring aging management are identified and that the effects of aging are effectively managed to maintain the CLB.

As discussed in UFSAR Section 1.4.10, a number of specific aspects of the GDC in Appendix A to 10 CFR Part 50 have become obligations or commitments applicable to the CNP design. If these aspects were determined to be pertinent to the license renewal IPA, the LRA discusses or references them. For example, LRA Section 2.3.3.6 states that maintaining dose to control room operators less than GDC-19 is a safety-intended function of the control room ventilation system. In addition, LRA Section 4.7.1.2 discusses the leak-before-break (LBB) analysis of the pressurizer surge line. This analysis credits provisions of GDC-4, "Environmental and Dynamic Effects Design Basis," to exclude from the plant's design basis the dynamic effects associated with postulated pipe rupture if the analysis approved by the NRC demonstrates that the probability of pipe rupture is extremely low. Reference 4.7-3 of the LRA provides the NRC approval of the LBB analysis.

In summary, the CNP design, as approved by the NRC in the September 10, 1973, operating license SER, was determined to meet the GDC that were current at the time of issuance of the operating license (*i.e.*, GDC published in Appendix A to 10 CFR Part 50). I&M did not perform a detailed comparison of the plant design to the GDC, but instead considered the plant design, as described in the CLB, as the basis for the license renewal evaluations in the IPA. The LRA and UFSAR Section 1.4.10 discuss specific cases in which I&M has committed to aspects of the GDC in Appendix A to 10 CFR Part 50, as appropriate.

Based on its review, the staff finds the applicant's response to RAI 2.2-4 acceptable because the applicant adequately explained how the differences in the design of Units 1 and 2 affected the IPA. Therefore, the staff's concern described in RAI 2.2-4 is resolved.

RAI 2.2-5

Many LRA Section 2 tables (*i.e.*, Tables 2.3.3-2, 2.3.3-3, and 2.3.4-3) list "fittings" as a component type subject to an AMR having the intended function of a pressure boundary. Fittings normally include piping system components such as elbows, tees, unions, reducers, and caps. However, the corresponding LRA table for the other auxiliary systems and steam and power conversion system (*i.e.*, Tables 2.3.3-5, 2.3.3-6, 2.3.3-11, 2.3.4-1, 2.3.4-2, and 2.3.4-4) do not include the component type "fittings," even though fittings are an integral part of these systems. In this RAI, the staff requested that the applicant identify components that were considered in the LRA tables as part of the component group "fittings," and explain why some of the LRA Section 2 tables did not include the component type "fittings."

In its response, dated May 7, 2004, the applicant stated:

> Piping system components such as elbows, tees, unions, reducers, and caps, are included in the component type "Fittings." In some of the LRA Section 2 (and Section 3) tables, these piping system components were included in component type "Piping." Fittings were included separately in those LRA tables where a fittings listing was not identical to piping or manifold (piping) listings in the table (*i.e.*, differences exist between the materials or environments applicable to the piping/manifold and those applicable to the fittings). Where the material/environment combinations applicable to the fittings are the same as the piping listings in a table, a separate listing is not necessary. Regardless of which component type was used for fittings that are an integral part of a system, all material and environmental combinations present in passive, long-lived components that perform or support an intended function within the system are reviewed and appropriately included for aging management.

Based on its review, the staff finds the applicant's response to RAI 2.2-5 acceptable because the applicant adequately explained how the component type "fittings" includes fittings of a material and environment combination different than that of the "piping" component type. Therefore, the staff's concern described in RAI 2.2-5 is resolved.

RAI 2.2-6

License renewal drawings for the essential service water (ESW) system for CNP, Units 1 and 2, (LRA-1-5113 and LRA-2-5113, respectively) show radiation monitoring alarms at locations M3 and M6. Similarly, the Units 1 and 2 license renewal drawings of the CCW system (LRA-15135 and LRA-25135, respectively) show radiation monitoring alarms at locations J6 and J7. In RAI 2.2-6, the staff asked the applicant to clarify whether these alarms penetrate the pressure boundary of the system piping. If they do, as recommended in Table 2.1-5 of the SRP-LR and Appendix B to NEI 95-10, Revision 3, the staff requested that the applicant identify the radiation monitoring alarms for the auxiliary systems that support the intended function of maintaining the pressure boundary and, thus, are within the scope of license renewal and subject to an AMR, in accordance with the requirements of 10 CFR 54.4(a)(1)(ii) and 10 CFR 54.21(a)(1).

In its response, dated May 7, 2004, the applicant stated that the review of the ESW and CCW systems includes the pressure boundary passive mechanical component for these radiation detectors under the component type "detector well" in LRA Tables 3.3.2-2 and 3.3.2-3.

Based on its review, the staff finds the applicant's response to RAI 2.2-6 acceptable because the applicant adequately explained how the component type "detector well" in the ESW and CCW systems includes the pressure boundary portions of the radiation detectors. Therefore, the staff's concern described in RAI 2.2-6 is resolved.

2.2.3 Conclusion

The staff reviewed LRA Section 2.2 and the supporting information in the CNP UFSARs to determine whether the applicant had omitted any structures and systems from the scope of license renewal. As a result of this review, the staff did not identify any omissions. On the basis of this review, the staff concludes that the applicant has appropriately identified the structures and systems that are within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 System Scoping and Screening Results—Mechanical Systems

This section documents the staff's review of the applicant's scoping and screening results for mechanical systems. Specifically, this section discusses the following mechanical systems:

- reactor coolant system
- engineered safety features
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements stated in 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived mechanical systems and components that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that the applicant did not omit any mechanical system components that meet the scoping criteria and are subject to an AMR.

Staff's Evaluation Methodology

The staff performed its evaluation of the information provided in the LRA in the same manner for all mechanical systems. The review sought to determine if the applicant identified components and supporting structures for specific mechanical systems that appear to meet scoping criteria specified in 10 CFR Part 54 as within the scope of license renewal in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Scoping To perform its scoping evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing the review on components that the applicant had not identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each mechanical system to determine if the applicant had omitted system components with intended functions delineated under 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the licensing basis documents to determine if the LRA specifies all intended functions delineated under 10 CFR 54.4(a). If the staff identified omissions, the staff requested additional information to resolve the discrepancy.

Screening Once the staff completed its review of the scoping results, it evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine if the functions are performed with moving parts or a change in configuration or properties, or if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those components that do not meet either of these criteria, the staff sought to confirm that these mechanical system components are subject to an AMR, as required by 10 CFR 54.21(a)(1). If the staff identified discrepancies, it requested additional information to resolve them.

The applicant did not supply marked drawings or any other means of identifying the specific components that are within the scope of license renewal meeting the criteria of 10 CFR 54.4(a)(2). Instead, it supplied a rollup of component types that represent those components meeting the criteria of 10 CFR 54.4(a)(2). Section 2.3.1 of the SRP-LR states the following:

> For a mechanical system that is within the scope of license renewal, the applicant should identify the portions of the system that perform an intended function, as defined in 10 CFR 54.4(b). The applicant may identify these particular portions of the system in marked-up piping and instrument diagrams (P&IDs) or other media. This is "scoping" of mechanical components in a system to identify those that are within the scope of license renewal for a system.

Because the information that the applicant provided deviated from the information that the staff needed to complete its review, the staff requested additional information about the methodology used for identifying these components.

RAI 2.3-1

Section 2.1.2.1.2, "Identifying Components Subject to Aging Management Review," of the LRA states that, "[license] renewal drawings were created by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an aging management review." However, the highlighted portions of license renewal drawings are bounded by a flag, which the legend of the drawing defines as the license renewal boundary. As such, the license renewal drawings indicate that the highlighted portions represent SSCs that are within the scope of license renewal. The staff asked the applicant to clarify this apparent discrepancy by confirming whether the highlighted portions represent SSCs that are (1) within the scope of license renewal or (2) within the scope of license renewal and subject to AMR.

In its response dated January 14, 2004, the applicant stated the following:

> The highlighted portions of the license renewal drawings represent systems, structures, and components that are within the scope of license renewal <u>and</u> subject to AMR. This is not indicative of a discrepancy between the text in LRA Section 2.1.2.1.2 and the manner in which the license renewal drawings were highlighted.
>
> LRA Section 2.1.2.1.2, "Identifying Components Subject to Aging Management Review," states the following: "[license] renewal drawings were created by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an aging management review." The license renewal boundary may be defined as the separation point between the portion of the system that requires an AMR (highlighted portion) and the portion of the system that does not require an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3-1 acceptable because it clarifies information in LRA Section 2.1.2.1.2. Therefore, the staff's concern described in RAI 2.3-1 is resolved.

2.3.1 Reactor Coolant System

Unless otherwise stated, the RCS description and the component descriptions apply to both CNP Units 1 and 2.

The RCS is designed to contain pressurized treated (borated) water while transporting heat from the reactor core to the steam generators. The system consists of four similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a RCP and a steam generator. In addition, the system includes a pressurizer, a pressurizer relief tank, and the necessary interconnecting piping and instrumentation. All major components are located in the reactor containment.

During operation, the RCPs circulate pressurized water through the reactor vessel and the reactor coolant loops. The water, which serves as a coolant, moderator, and solvent for boric acid (chemical shim control), is heated as it passes through the core. The water then flows to the steam generators, where the heat is transferred to the secondary system. The coolant exits the steam generators, returning to the RCPs to repeat the cycle.

System pressure is controlled in the pressurizer, where electrical heaters and water sprays maintain water and steam in equilibrium. The pressurizer lower half is filled with saturated water, and the top half is filled with saturated steam. Pressurizer heaters in the liquid space form steam to raise and maintain pressure. Pressurizer sprays in the steam space condense steam to lower pressurizer pressure.

Three spring-loaded safety valves and three power-operated relief valves (PORVs) connected to the pressurizer provide overpressure protection. The low-temperature overpressure protection system (LTOPS) provides overpressure protection during low-temperature operation of the RCS, when the reactor vessel is vulnerable to brittle fracture failure. The LTOPS is a combination of automatic actuation devices, passive relief devices, and administrative controls designed to ensure that RCS pressure is maintained within the limits defined in Appendix G to 10 CFR Part 50.

A material compatible with the system temperature insulates components and piping in the RCS to reduce heat loss. Insulation material used for RCS components has low soluble chloride and other halide content to minimize the possibility of stress-corrosion cracking (SCC) of stainless steel.

The RCS is within the scope of license renewal as a safety related system, as it is in accordance with 10 CFR 54.4(a)(1). Certain nonsafety related portions of the system are within the scope of license renewal as potentially affecting safety related components, which is in accordance with 10 CFR 54.4(a)(2). Pursuant to 10 CFR 54.4(a)(3), the RCS is within the scope of license renewal for PTS requirements, SBO (as the RCS pressure boundary must be maintained during SBO), and FP for safe shutdown following a fire.

The applicant used the RCS intended function (*i.e.* to provide a pressure and fission product barrier) to establish the CNP RCS Class 1 evaluation boundary. The evaluation boundary includes the reactor vessel internals (RVI). The CNP RCS Class 1 evaluation boundary corresponds to RCS pressure boundary components within the ASME Code, Section XI, Subsection IWB, inspection boundary and includes the non-Class 1 instrumentation and vent lines attached to RCS components. The evaluation boundary also includes the secondary side of the steam generators (*i.e.*, vessel shell and nozzles attached to the vessel that are inspected in accordance with ASME Code, Section XI, Subsection IWC). Components within the RCS Class 1 evaluation boundary are hereafter referred to as Class 1 components.

The following Class 1 components support the RCS system intended functions and are subject to an AMR:

- reactor vessel and control rod drive mechanism pressure boundary
- reactor vessel internals
- Class 1 piping, valves, and reactor coolant pumps

- pressurizer
- steam generators

The RCS Class 1 piping evaluation boundary extends into portions of ancillary systems attached to the RCS. The Class 1 components of the systems listed below are evaluated with the RCS. The non-Class 1 portions of the systems listed below are evaluated in the referenced sections of this SER:

- chemical and volume control system (Section 2.3.3.5)
- emergency core cooling system (Section 2.3.2.3)
- nuclear sampling (Section 2.3.3.11)

The RCS evaluation includes the following systems in their entirety:

- control rod drives (included with the reactor vessel)
- reactor vessel level instrumentation system (RVLIS) (included with RCS piping)

2.3.1.1 Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

2.3.1.1.1 Summary of Technical Information in the Application

In Section 2.3.1.2 of the LRA, the applicant described the reactor vessel and control rod drive mechanism (CRDM) pressure boundary. The reactor vessel contains the nuclear fuel core, core support structures, control rods, and other parts directly associated with the core. The vessel is cylindrical with a welded hemispherical bottom head and a removable, hemispherical upper head. The vessel has four inlet nozzles and four outlet nozzles with weld-deposited cladding on inner surfaces. These eight nozzles are arranged circumferentially around the vessel at the nozzle belt of the vessel, below the vessel closure flange but above the top of the core.

The CRDM nozzles with attached nozzle adapters and a vent pipe penetrate the reactor vessel closure heads. Partial penetration welds attach these nozzles to the head. The pressure-retaining items associated with the CRDMs include pressure housings and rod travel housings. Each CRDM pressure housing is threaded onto the adapter on top of the reactor pressure vessel (RPV) and seal welded or mechanically clamped. The closure at the top of the rod travel housing includes a threaded cap with a canopy seal weld or conoseal joint.

Two hollow, metallic O-rings seal the reactor vessel closure head. Two leak-off connections, one between the inner and outer ring and one outside the outer ring, detect seal leakage. The O-rings are replaced regularly and are therefore not subject to an AMR.

Nozzle and conduit assemblies, through which the in-core instrumentation thimble tubes are inserted into the reactor core, penetrate the bottom head.

The CNP reactor vessels and CRDMs were constructed in accordance with the requirements of ASME Code, Section III.

Section 2.3.1.3 of the LRA discusses the reactor vessel internals, and LRA Section 2.3.1.4 discusses the RCS piping attached to reactor vessel safe ends. Section 4.2.2.1, "Reactor Vessel," of the CNP UFSAR provides additional information regarding the CNP reactor vessel.

In Table 2.3.1-1 of the LRA, the applicant identified the reactor vessel and CRDM pressure boundary component types that are within the scope of license renewal and subject to an AMR, including the bottom head, shell—nozzle course, upper head, inlet nozzles, outlet nozzles, shell rings, weld buildup support pads (external attachment), inlet nozzle safe ends, outlet nozzle safe ends, vessel flange, closure head flange, closure studs, closure nuts, washers, CRDM nozzles, CRDM housing adapter, in-core instrumentation nozzles, in-core instrumentation nozzle safe ends, bottom-mounted instrumentation (BMI) thimble guide tubes, BMI thimble tubes and bullet plugs, thimble seal table, core support lugs, vent line (nozzle and elbow), vent line safe end, CRDM housing, core exit thermocouple nozzle assembly, holddown nut, compression collar and lockwasher, CRDM housing cap, lifting lugs, ventilation shroud support ring, and flange leak tubes.

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Sections 2.3.1.2, 2.3.1.3, and 2.3.1.4 and CNP UFSAR Section 4.2.2.1 to determine whether the applicant identified the reactor vessel and CRDM pressure boundary system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3, "Scoping and Screening Results—Mechanical Systems," of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated in 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that it did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In reviewing LRA Section 2.3.1.2, the staff needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated May 10, 2004, the staff issued an RAI to assist the staff in determining whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAI and the applicant's related response.

Note 1 in Table 2.3.1.2-1 of the LRA states that although the vessel lifting lugs do not directly support an intended function, the table includes them for completeness. However, the staff's position is that the subject component should be within the scope according to 10 CFR 54.4(a)(2) because its failure may prevent some of the safety related components from performing their intended functions if the RPV head drops while being lifted. In RAI 2.3.1.2-1, the staff requested that the applicant state the basis, pursuant to 10 CFR Part 54, on which it determined components (specifically vessel lifting lugs) to be within scope and requiring aging management.

In its response dated May 20, 2004, the applicant stated that although the safety related reactor vessel head (RVH) is credited for performing a pressure boundary intended function, the RVH lifting lugs are not relied on to support this license renewal intended function. Since the lifting lugs are part of the RVH, the applicant considered them to be safety related and included them within the scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.2-1 acceptable, because the applicant included the components within the scope requiring an AMR and identified the component type in the LRA which includes the subject components. Therefore, the staff's concerns described in RAI 2.3.1.2-1 are resolved.

2.3.1.1.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI response, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the reactor vessel and CRDM system. Therefore, the staff concludes that the applicant has adequately identified the reactor vessel and CRDM system SCs 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 vessel and CRDM system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Vessel Internals

2.3.1.2.1 Summary of Technical Information in the Application

In Section 2.3.1.3 of the LRA, the applicant described the reactor vessel internals (RVI) which consist of the lower core support structure (including the entire core barrel, thermal shield, and baffle/former assembly), the upper core support, and the in-core instrumentation support structures. Reactor coolant flows from the vessel inlet nozzles down the annulus between the core barrel and the vessel wall, then into a plenum at the bottom of the vessel. It then reverses direction and flows up through the core support and through the lower core plate. After passing through the core, the coolant enters the region of the upper support structure, then flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles.

Reactor vessel internals perform the following functions:

- provide support and orientation for the reactor core
- provide support, orientation, guidance, and protection of the control rod assemblies
- direct reactor coolant flow past the reactor core
- provide support, guidance, and protection for the in-core instrumentation
- limit the core support structure displacement
- provide gamma and neutron shielding for the reactor pressure vessel

The applicant reviewed the current design and operation of the RVI using the process described in LRA Section 2.3.1.1 and confirmed that the CNP RVI are bounded by the description provided in WCAP-14577-A. The component intended functions for the RVI are consistent with the intended functions identified in WCAP-14577-A. The NRC review of WCAP-14577-A resulted in applicant action items, which are documented in the corresponding NRC safety evaluation (SE), dated February 10, 2001. Table 2.3.1-6 of the LRA provides CNP-specific responses to those applicant action items relevant to the identification of RVI components subject to an AMR. Section 3.2.1 (Unit 1), "Mechanical Design and Evaluation," and Section 3.2.2 (Unit 2), "Reactor Vessel Internals," of the CNP UFSAR provide additional information regarding the CNP RVI.

In Table 2.3.1-2 of the LRA, the applicant identified the RVI component types that are within the scope of license renewal and subject to an AMR for the lower core support structure, including the core barrel (barrel, flange, outlet nozzle, and fasteners), core former plates, core baffle plates, core former bolts, core baffle bolts, lower core plate, lower support columns, diffuser plate, lower support plate, lower core plate support column cap, secondary core support assembly (energy absorbers), clevis insert block and fastener, and thermal shield.

For the upper core support structure, the applicant identified the upper support plate, deep beam sections, upper support columns, support column bolts (upper and lower), upper core support column mixing device, upper core support column orifice base, upper core plate, upper core plate alignment pins, radial keys, holddown spring, control rod guide tube pin, fuel assembly guide pin, and guide tube assemblies.

For the in-core instrumentation support structure, the applicant identified the upper system (thermocouples) and lower system (flux thimbles).

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 and CNP UFSAR Sections 3.2.1 (Unit 1) and 3.2.2 (Unit 2) to determine whether the applicant identified the RVI system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

In reviewing LRA Section 2.3.1.3, the staff identified an area in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued an RAI concerning the specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAI and the applicant's related response.

Chapter 3 of the UFSAR (page 11 for Unit 1 and page 29 for Unit 2) states that a small amount of inlet water is directed into the vessel head plenum to provide cooling of the vessel head. According to WCAP-14577-A, the components associated with this cooling system should be within the scope of license renewal as requiring aging management. Because Table 2.3.1-2 of the LRA does not identify the subject components, the staff asked the applicant in RAI 2.3.1.3-1 to confirm whether the components associated with RPV head cooling system are within scope as requiring aging management.

In its response dated May 20, 2004, the applicant stated that to provide vessel head plenum cooling, a small amount of bypass flow is directed from the inlet downcomer into the upper head. The flowpath for this bypass flow consists of 16 spray holes located in the flange of the core barrel. Similar spray holes are provided at corresponding locations in the upper support plate. These spray holes are located outside the outer diameter of the holddown spring, allowing a small, unimpeded bypass flow from the inlet downcomer below the core barrel flange, through the annulus outside of the holddown spring, and up through the upper support plate into the upper head plenum. The applicant clarified that at CNP, the spray holes are included with the component types "core barrel" and "upper support plate," and are listed as subject to an AMR in LRA Tables 2.3.1-2 and 3.1.2-2. Based on its review, the staff finds the applicant's response to RAI 2.3.1.3-1 acceptable, because the applicant included the components as within scope and as requiring an AMR and identified the component type in the LRA which includes the subject components. Therefore, the staff's concerns described in RAI 2.3.1.3-1 are resolved.

2.3.1.2.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI response, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the RVI system. Therefore, the staff concludes that the applicant has adequately identified the RVI system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the RVI system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Class 1 Piping, Valves, and Reactor Coolant Pumps

2.3.1.3.1 Summary of Technical Information in the Application

In Section 2.3.1.4 of the LRA, the applicant described the Class 1 piping, valves, and RCP. The RCS Class 1 piping and associated pressure boundary components consist of the following:

- primary loop piping interconnecting the reactor vessel with the steam generator and RCP in each loop
- pressurizer surge, spray, and relief lines
- auxiliary spray line
- normal and alternate charging lines
- letdown and excess letdown line
- residual heat removal lines
- safety injection lines
- accumulator lines
- sample/instrument lines (includes RVLIS)
- vent pipe from the reactor vessel head

- resistance temperature detector bypass lines, loop bypass lines, direct immersion resistance temperature detectors, thermowells, sample and spray scoops, and reactor vessel flange leak-off lines

For convenience, this section includes portions of RCS instrumentation and sampling tubing, such as the reactor coolant pressure boundary items (valves and tubing) downstream of the instrument root valves. The pressure-retaining portion of Class 1 valves consists of the valve body, bonnet, and closure bolting. The RCS Class 1 valves are welded in place, with the exception of the pressurizer safety valves, which have flanged connections.

The following portions of the RCPs perform a pressure boundary function:

- pump casings
- main closure flanges
- seals
- thermal barrier coil heat exchangers
- pressure-retaining closure bolting

The applicant periodically monitors, inspects, and replaces (as required) the RCP seals; therefore, they are not subject to an AMR.

Class 1 piping is designed and constructed in accordance with United States of America Standard (USAS) B31.1. The RCS valves are designed and constructed to ASME/American National Standards Institute (ANSI) B-16.5 or Manufacturers Standardization Society of the Valves and Fittings Industry (MSS)-SP-66, and ASME Code, Section III. The RCPs are designed and constructed using ASME Code, Section III, as a guide. These codes are consistent with WCAP-14575-A.

The applicant reviewed the current design and operation of the reactor coolant piping using the process described in Section 2.3.1.1 of the LRA. This review confirmed that the CNP Class 1 piping, valves, and RCPs are bounded by the description provided in WCAP-14575-A with regard to the following:

- design criteria and features
- materials of construction
- fabrication techniques
- installed configuration
- modes of operation
- environments/exposures

The component intended functions are consistent with the intended functions identified in WCAP-14575-A. The NRC review of WCAP-14575-A resulted in applicant action items, which are documented in the corresponding NRC SE, dated November 8, 2000. Table 2.3.1-7 of the LRA provides CNP-specific responses to those applicant action items relevant to the identification of reactor coolant piping components subject to an AMR.

The following sections of the CNP UFSAR provide additional information regarding the CNP Class 1 piping, valves, and RCPs:

- Section 4.2.2.5, "Reactor Coolant Pump"
- Section 4.2.2.6, "Reactor Coolant System Vents"
- Section 4.2.2.7, "Reactor Coolant Piping"
- Section 4.2.2.8, "Valves"

In Table 2.3.1-3 of the LRA, the applicant identified the Class 1 piping component types that are within the scope of license renewal and subject to an AMR, including hot-leg pipe and fittings, cold-leg pipe and fittings, crossover leg pipe and fittings, pressurizer surge line, pipe and fittings (including blind flanges) nominal pipe size (NPS) 4", pipe and fittings (including blind flanges) less than NPS 4", branch nozzles NPS 4", branch nozzles less than NPS 4" (includes sample and spray scoops, thermowells, and immersion resistance temperature detectors), thermal sleeves, and orifices.

The applicant also identified Class 1 valve component types, including Class 1 valve bodies and bonnets (greater than or equal to 2.5"), Class 1 valve bodies and/or bonnets (less than or equal to 2"), and bolting material (for valves and blind flanges), as being within the scope of license renewal and subject to an AMR.

Finally, the applicant identified RCP component types, including casing, main closure flange, main flange bolts, and thermal barrier heat exchanger as being within the scope of license renewal and subject to an AMR.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 and CNP UFSAR Sections 4.2.2.5, 4.2.2.6, 4.2.2.7, and 4.2.2.8 to determine whether the applicant identified the Class 1 piping, valves, and RCP system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

In reviewing LRA Section 2.3.1.4, the staff identified two areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated May 10, 2004, the staff issued RAIs concerning these issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

RAI 2.3.1.4-1

The staff's position is that unless the applicant provides plant-specific justification, the reactor vessel flange leak-off lines should be within scope and require aging management. In RAI 2.3.1.4-1, the staff requested the applicant to confirm whether the component types listed in

Table 2.3.1-3 of the LRA include the subject components. If not, then the staff asked the applicant to identify the subject components as within scope and requiring aging management or provide a plant-specific justification.

In its response dated May 20, 2004, the applicant stated that the flange leak-off lines are included within the scope of license renewal and require an AMR. The component type "flange leak tubes" listed in LRA Table 2.3.1-1 includes the flowpath from the O-ring groove to the outer surface of the reactor vessel flange. Downstream of the outer surface of the reactor vessel, license renewal drawings LRA-1-5128 and LRA-2-5128 show the flange leak-off lines at location G5. Table 2.3.1-3 includes them as the following component types:

- piping and fittings (including blind flanges) less than NPS 4"
- Class 1 valve bodies and/or bonnets less than or equal to 2"

Based on its review, the staff finds the applicant's response to RAI 2.3.1.4-1 acceptable, because the applicant included the components within the scope of license renewal requiring an AMR and identified the component type in the LRA which includes the subject components. Therefore, the staff's concern described in RAI 2.3.1.4-1 is resolved.

RAI 2.3.1.4-2

The staff also requested additional information regarding the RCP lubricating oil collection subsystem which is regulated pursuant to 10 CFR Part 50, Appendix R, III.O. This regulation indicates that the RCP lubricating oil collection subsystem is designed to collect oil from the RCPs and drain it to a collection tank to prevent a fire in the containment building during normal plant operations. The staff's maintains that the subsystem and the tank should be within the scope of 10 CFR Part 54 as requiring aging management. However, LRA Table 2.3.1-3 did not identify the subject components; therefore, in RAI 2.3.1.4-2, the staff asked the applicant to provide an explanation.

In its response dated May 20, 2004, the applicant stated that the lubricating oil collection system is a non-Class 1 system with an intended function of meeting FP requirements; therefore, the FP system AMR includes the lubricating oil collection system. Table 2.3.3-7 of the LRA lists the system component types "fittings," "piping," "tank," and "valve" as subject to an AMR for the FP system. Table 3.3.2-7 of the LRA includes components in the lubricating oil collection system with the external and internal environments of lubricating oil and borated water leakage, which LRA Table 3.0-1 identifies as environments specific to the lubricating oil collection system.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.4-2 acceptable, because the applicant included the components as within the scope of license renewal and requiring an AMR and identified the component type in the LRA which includes the subject components. Therefore, the staff's concern described in RAI 2.3.1.4-2 is resolved.

2.3.1.3.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the Class 1 piping, valves, and

RCP system. Therefore, the staff concludes that the applicant adequately identified the Class 1 piping, valves, and RCP system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the Class 1 piping, valves, and RCP system SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Pressurizer

2.3.1.4.1 Summary of Technical Information in the Application

In Section 2.3.1.5 of the LRA, the applicant described the pressurizer. The pressurizer is a low-alloy steel (LAS), vertically oriented, cylindrical vessel with hemispherical top and bottom heads and austenitic stainless steel cladding on interior surfaces that are exposed to the reactor coolant. The pressurizer is connected to the RCS on one of the hot legs of a coolant loop. Electrical heaters are installed through the bottom head of the pressurizer, while the spray nozzle, relief, and safety valve connections are located in the top head of the pressurizer. The pressurizer includes the vessel, attached nozzles, and safe ends out to the connection with RCS piping. *Section 2.3.1.4 of the LRA discusses the valves (i.e., safety and relief), instrument* lines, and other piping connected to the pressurizer.

The applicant reviewed the current design and operation of the Unit 1 and 2 pressurizers using the process described in Section 2.3.1.1 of the LRA. It confirmed that both CNP pressurizers are bounded by the description provided in WCAP-14574-A. The pressurizers were designed and constructed in accordance with ASME Code, Section III, which is consistent with WCAP-14574-A. The component intended functions for the pressurizers include the intended functions identified in WCAP-14574-A.

In addition to the functions identified in WCAP-14574-A, the applicant identified an additional function of pressure control. The pressurizer spray head and heaters provide pressure control during certain DBEs. The NRC review of WCAP-14574-A resulted in applicant action items, which are documented in the corresponding NRC SE, dated October 26, 2000. Table 2.3.1-8 of the LRA provides the CNP-specific responses to those applicant action items relevant to the identification of pressurizer components subject to an AMR. Section 4.2.2.2, "Pressurizer," of the CNP UFSAR provides additional information regarding the CNP pressurizers.

In Table 2.3.1-4 of the LRA, the applicant identified the pressurizer component types that are within the scope of license renewal and subject to an AMR, including lower head, shell, upper head, surge nozzle, spray nozzle, relief nozzle, safety nozzle, surge nozzle safe end, spray nozzle safe end, relief nozzle safe end, safety nozzle safe end, surge and spray nozzle thermal sleeve, heater well nozzles and coupling, immersion heater sheaths, heater support plates, heater support plate brackets, heater support plate bracket bolts, spray head, spray head locking bar, spray head coupling, support skirt and flange, seismic lugs, valve support bracket lugs, instrument nozzles and couplings, manway insert, manway forging, manway cover, and manway cover bolts/studs.

2.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.5 and CNP UFSAR Section 4.2.2.2 to determine whether the applicant identified the pressurizer system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

In reviewing LRA Section 2.3.1.5, the staff needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued RAIs concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

RAI 2.3.1.5-1

In the past, the applicant observed intergranular and transgranular type SCC in the welded section of pressurizer instrumentation nozzles in Westinghouse PWRs. In RAI 2.3.1.5-1, the staff asked the applicant to confirm whether it performed an AMR for the welded portion of the instrumentation nozzles.

In its response dated May 20, 2004, the applicant stated that it performed an AMR for the attachment welds of the pressurizer instrument nozzles at CNP. Similar to other pressurizer nozzles such as the spray, surge, and relief nozzles, it reviewed the instrument nozzle attachment welds with the welded item itself and included them in the component type "instrument nozzles and couplings" in LRA Table 2.3.1-4. The AMR results for pressurizer instrument nozzles and couplings, as listed in LRA Table 3.1.2-4, include the attachment welds.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.5-1 acceptable because the applicant included the components as within the scope of license renewal and requiring an AMR and identified the component type in the LRA that includes the subject components. Therefore, the staff's concern described in RAI 2.3.1.5-1 is resolved.

RAI 2.3.1.5-2

Drawing 5128A and Table 2.3.1-4 in the LRA do not include the pressurizer relief/quench tank as within scope. For the staff to determine whether the exclusion is justified, the staff asked, in RAI 2.3.1.5-2, the applicant to provide the following additional information:

(a) Does the failure of pressurizer relief tank prevent effective pressure control or prevent depressurization through the relief/safety valves?

(b) In the event the relief tank is not functional, and as a result, high pressure and high velocity steam need to be discharged into the containment, what are the consequences? The response should include discussions on potential of failure of other safety related components by the discharging steam.

In its response dated May 20, 2004, the applicant stated the following:

(a) The function of the pressurizer relief tank (PRT), as described in UFSAR Section 4.2.2.3, is to condense and cool the discharge from the pressurizer safety and relief valves, as well as several smaller relief valves. By means of its connection to the waste disposal system, the PRT also provides a means for removing any non-condensable gases, which might collect in the pressurizer, from the reactor coolant system. The PRT does not serve a pressurizer pressure control or depressurization prevention function.

(b) The consequences of a steam discharge from the PRT to the containment atmosphere are enveloped by various safety analyses described in detail in each unit's UFSAR Chapter 14. UFSAR Section 14.2.5 discusses the analysis of a steam pipe rupture. UFSAR Section 14.3.1 describes the analysis for a large break loss of coolant accident. Unit 2 UFSAR Section 14.4.11, which includes the Unit 1 analysis, states that equipment inside containment must be qualified to demonstrate that it can perform its safety related function following a high-energy line break (HELB). Unit 2 UFSAR Tables 14.4.2.1 and 14.4.2.1A include pressurizer safety and relief valves, and supporting components, in the equipment required for shutdown following a HELB. The PRT is not included in the lists of equipment in UFSAR Tables 14.4.2.1 or 14.4.2.1A.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.5-2 acceptable because, as described above, the applicant explained why the component does not meet the scoping and screening criteria outlined in 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) and, thus, is not required to be in the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.1.5-2 is resolved.

RAI 2.3.1.5-3

Table 2.3.1-4 of the LRA listed spray head as a component type subject to an AMR with an intended function of pressure control. Section 2.3.1.5, Page 2.3-10, of the LRA states that the spray head and heaters provide pressure control during certain DBEs. However, LRA drawing 5128A shows the components as not within scope. In RAI 2.3.1.5-3, the staff asked the applicant to clarify this apparent inconsistency.

In its response dated May 20, 2004, the applicant stated that the pressurizer spray head is within scope and that it performed an AMR on this item. This review resulted in LRA Tables 2.3.1-4 and 3.1.2-4 listing the component types "spray head," "spray head locking bar," and "spray head coupling." The applicant inadvertently omitted the highlighting of the spray head on license renewal drawings LRA-1-5128A and LRA-2-5128A.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.5-3 acceptable because the applicant included the components as within scope and requiring an AMR and identified the component type in the LRA which includes the subject components. Therefore, the staff's concern described in RAI 2.3.1.5-3 is resolved.

2.3.1.4.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the pressurizer system. Therefore, the staff concludes that the applicant adequately identified the pressurizer system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the pressurizer system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.5 Steam Generators

2.3.1.5.1 Summary of Technical Information in the Application

In Section 2.3.1.6 of the LRA, the applicant described the steam generators. The steam generators are vertical shell and U-tube heat exchangers with integral moisture separating equipment. Reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. A vertical partition plate extending from the head to the tubesheet divides the head into inlet and outlet chambers. Feedwater enters the steam generators and is distributed through a feedwater ring located just below the moisture separators. Feedwater flows down between the steam generator shell and tube bundle wrapper and into the tube bundle just above the tubesheet. Steam is generated on the shell side of the tube bundle and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. Each Unit 1 steam generator outlet nozzle contains an integral flow-restricting venturi that limits steam release in the event of a main steamline break (MSLB).

The steam generators include the following:

- steam generator upper and lower shells
- transition cone
- elliptical upper head
- hemispherical bottom head
- primary and secondary manways, nozzles, and safe ends
- thermal sleeves
- partition plate
- tubesheet
- U-tubes
- interior attachments
- instrumentation ports and handholes
- associated pressure-retaining bolting

The CNP steam generators were constructed in accordance with the requirements of ASME Code, Section III. The Unit 1 steam generator replacement in 2000 included installation of a new lower assembly (including tube bundle), new steam drum internals, and a new feedwater distribution system. The steam drum internals were installed in the refurbished, original steam drum shell. The Unit 2 steam generator replacement in 1988 included installation of a new lower assembly (including tube bundle) and refurbishment of the upper assembly (steam drum) and associated internals.

Section 4.2.2.4, "Steam Generators," of the CNP UFSAR provides additional information regarding the CNP steam generators.

In Table 2.3.1-5 of the LRA, the applicant identified the primary-side steam generator component types that are within the scope of license renewal and subject to an AMR, including primary head, primary nozzles, primary nozzle safe ends, partition plates, nozzle dam retention rings, primary manway insert plate, primary manway cover, primary manway closure bolting, tubes/plugs, and tubesheet.

The applicant also identified the secondary-side externals, including lower shell; upper shell; transition cone; steam drum; elliptical upper head; feedwater nozzles; feedwater nozzle thermal sleeve (Unit 1 only); main steam nozzles; feedwater safe ends (Unit 1 only); secondary blowdown and instrumentation connections; recirculation connections (Unit 1 only); secondary shell drain connections (Unit 2 only); secondary handhole ports; inspection ports; secondary handhole port covers; inspection port covers; recirculation port covers (Unit 1 only); secondary manways; secondary manway covers; secondary manway, handhole, recirculation (Unit 1 only) and inspection port closure bolting; steamflow restrictors (Unit 1 only); feedwater elbow thermal liners (Unit 2 only); and feedwater liner piston rings (Unit 2 only).

Finally, the applicant identified the secondary-side internals, including tube wrappers (shroud), tube support plates (Unit 2 only), antivibration bar (Unit 2 only), tube support plate stayrods (Unit 2 only), tube support plate spacers (Unit 2 only), tube support plate stayrod nuts (Unit 2 only), tube support plate stayrod washers (Unit 2 only), antivibration bars retaining rings (Unit 2 only), lattice grid ring (Unit 1 only), U-bend arch bars (Unit 1 only), lattice grid ring studs (Unit 1 only), lattice grid bars (Unit 1 only), U-bend flat bars (Unit 1 only), and J-tabs (Unit 1 only) as being within the scope of license renewal and subject to an AMR.

2.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.6 and CNP UFSAR Section 4.2.2.4 to determine whether the applicant identified the steam generator system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

In reviewing LRA Section 2.3.1.6, the staff identified two areas where it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued RAIs concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

RAI 2.3.1.6-1

In Table 2.3.1-5 of the LRA, the staff observed that the applicant identified the steam generator partition plate as within the scope of license renewal and requiring aging management. However the table does not identify one of the most significant intended functions of the component: flow distribution. The steam generator partition plate is located in the lower head of each steam generator and separates the hot-leg primary fluid from the cold-leg primary fluid. Reactor coolant is located on both sides of the steam generator partition plate. The staff understands that the intended function of the steam generator partition plates is flow distribution (i.e., forcing the hot-leg primary flow through the steam generator tubes, thereby enabling the steam generator to perform its primary function of heat transfer). As a result, failure of the partition plate will degrade the heat transfer function of the steam generator. Degradation of the heat transfer function of the steam generator has several safety consequences, including the inability of the reactor to safely shut down and loss of natural circulation heat removal through the steam generator which may be credited for prevention or mitigation of DBEs, accidents, and/or NRC regulated events. In addition, the staff's position is that a partition plate degraded by aging may develop loose parts, which may lead to flow blockage of the steam generator tubes and thus cause degradation of the steam generator heat transfer function. In RAI 2.3.1.6-1, the staff asked the applicant to specify flow distribution as one of the intended functions of steam generator partition plates and to affirm the existence of an AMP that provides reasonable assurance that the plates will not fail in a manner which can result in the primary coolant bypassing the steam generator tubes and/or generate loose parts.

In its response dated May 20, 2004, the applicant stated that the steam generator partition plate is a pressure boundary between the RCS inlet and outlet areas of the lower head. This partition plate separates the primary coolant inlet chamber from the outlet chamber. Failures that bypass the steam generator tubes and loose parts that could cause flow blockage of the steam generator tubes would be readily apparent because of the impact on steam generator performance during normal power operation. The applicant further stated that aging effects associated with the component type "partition plate" listed in LRA Table 3.1.2-5 include loss of material and cracking. The Water Chemistry Program, Alloy 600 Aging Management Program, and Inservice Inspection Program manage these aging effects. These programs provide reasonable assurance that the steam generator partition plate will not fail in a manner that could result in reactor coolant bypassing the steam generator tubes or generating loose parts. Furthermore, the applicant stated that the addition of flow distribution as an intended function for the partition plate would have no effect on the applicant's AMR results.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.6-1 acceptable, because the applicant included the components within the scope requiring an AMR for all of its intended functions, including the flow distribution. The applicant also identified the component type in the LRA that includes the subject components. Therefore, the staff's concern described in RAI 2.3.1.6-1 is resolved.

RAI 2.3.1.6-2

The staff notes that LRA Table 2.3.1-5 does not identify steam generator feedwater ring and J-tubes as within the scope of license renewal and requiring aging management. In RAI 2.3.1.6-2, the staff asked the applicant to provide the following additional information to justify the exclusion of subject components from the scope:

(a) In page 19 (Chap.4) of the UFSAR, it is stated that the "J" tubes prevent rapid drainage of the feedwater ring due to a drop in steam generator water level and thus eliminate or reduce the possibility of water hammer in the feedwater line. On the basis of the above statement made in the UFSAR, it appears that the subject components are needed to prevent or mitigate accidents; and therefore, should be in scope in accordance with 10 CFR 54.4(a)(1)(iii).

(b) Explain, if the components were relied upon to demonstrate compliance during a design basis event, such as feedwater line break accident, and/or Commission's regulated events.

(c) Explain, why failure of the components will not prevent in-scope components within the steam generator (SG) from performing their intended functions.

(d) Explain, whether the subject components are covered under any existing inspection and/or monitoring programs, such as Steam Generator Integrity Program.

In its response dated May 20, 2004, the applicant stated the following:

(a) The SG feedwater ring and "J" tubes are not subject to AMR because they do not directly support the SG pressure boundary function. Prevention of conditions that may result in water or steam hammer is sound engineering practice exercised throughout the entire CNP plant design. Water hammer is not a DBE; and the text in the UFSAR only identifies a design feature of the feedwater ring and "J" tubes that may reduce the potential for water hammer in the event of a reduction in SG water level below the feedwater ring.

(b) There are no DBEs or regulated events at CNP that rely upon the SG feedwater ring or "J" tubes to demonstrate successful mitigation and recovery from the event.

(c) As stated by the Commission in the Statement of Considerations for the Final Part 54 Rule, "Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required." CNP has not experienced any water hammer events in the feedwater rings that led to a line failure or DBE. Pressure boundary would be maintained in the event of failure of the "J" tubes and feedwater ring.

(d) The SG feedwater ring and "J" tubes are monitored as part of the SG Monitoring Program, which implements the SG Integrity Program described in LRA Section B.1.31. The chemistry of the feedwater and the secondary fluid within the SG is controlled by the Primary and Secondary Water Chemistry Control Program, which is described in LRA Section

B.1.40.1, to mitigate corrosion and stress corrosion cracking. No new AMPs are required for these items.

Based on its review, the staff finds the applicant's response to RAI 2.3.1.6-2 acceptable because, as described above, the applicant explained why the component did not meet the scoping and screening criteria outlined in 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) and, therefore, is not required to be within the scope of license renewal. The staff's concern described in RAI 2.3.1.6-2 is resolved.

2.3.1.5.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the steam generators. Therefore, the staff concludes that the applicant adequately identified the steam generator SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the steam generator SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

In Section 2.3.2 of the LRA, the applicant identified the SCs of the engineered safety features (ESF) that are subject to an AMR for license renewal, including the following:

- containment spray
- containment isolation
- emergency core cooling
- containment equalization/hydrogen skimmer

2.3.2.1 Containment Spray

2.3.2.1.1 Summary of Technical Information in the Application

In Section 2.3.2.1 of the LRA, the applicant described the containment spray. The containment spray system provides spray cooling water to the containment atmosphere during a loss-of-coolant accident (LOCA) or steamline break accident inside containment. This cooling water limits the peak pressure in the containment to below the containment design pressure. As a secondary function, the containment spray system removes radioactive iodine from the containment atmosphere during a LOCA.

The refueling water storage tank (RWST) is included in the containment spray system boundary. The RWST provides a source of borated water for the emergency core cooling system (ECCS) and containment spray system during the injection phase of an accident. Sodium hydroxide solution from a single spray additive tank is mixed into both spray flow trains to provide adequate iodine removal. Once the RWST's supply of water is exhausted, the containment spray system takes suction from the water accumulated in the containment recirculation sump. Additional spray ring headers, supplied by a portion of the recirculation flow from the residual heat removal (RHR) system, supplement the heat removal capability of the containment spray system and are included in the review of containment spray.

The containment spray system consists of two independent, 100-percent capacity flow trains with diverse power sources. Each train includes the following:

- pump
- spray additive eductor
- heat exchanger
- ring headers in both the upper and lower containment volumes, with the associated spray nozzles, piping, valves and instrumentation necessary for operation

In support of Appendix R requirements, the RWST provides a sufficient volume of borated water to support shutting down the unit or the opposite unit. Therefore, the containment spray system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

In Table 2.3.2-1 of the LRA, the applicant identified the containment spray component types that are within the scope of license renewal and subject to an AMR, including bolting, eductor, heat exchanger (shell), heat exchanger (tubes), heater housing (RWST electric heater), manifold (piping), orifice, piping, pump casing, spray nozzle, tank, thermowell, tubing (instrument piping), and valve.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 and UFSAR Sections 6.1, 6.2, and 6.3 to determine whether the applicant identified the containment spray system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

The staff found that those portions of the containment spray system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, that the applicant identified them in LRA Section 2.3.2.1, and that Table 2.3.2-1 includes the containment spray system components that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.1.3 Conclusion

During its review of information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the containment spray system. Therefore, the staff concludes that the applicant adequately identified the containment spray system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a) and that the applicant adequately identified the containment spray system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Isolation

2.3.2.2.1 Summary of Technical Information in the Application

In Section 2.3.2.2 of the LRA, the applicant described the containment isolation system. Mechanical penetrations ensure that the primary containment can be isolated under accident conditions to limit the release of radioactivity. For license renewal, the scope of the containment isolation system is the passive mechanical penetration components (piping and valves) that are not included within another AMR. In general, the applicant reviewed the mechanical penetrations for systems with a system-level AMR with that system. Section 2.4.1 of the LRA addresses aging management for the structural elements of the mechanical penetrations.

This grouping of the containment isolation components from various plant systems into one consolidated review is appropriate, as indicated in Section 2.1.3.1 of the SRP-LR, which states, "An applicant may take an approach in scoping and screening that combines similar components from various systems. For example, containment isolation valves from the various systems may be identified as a single system for purpose of license renewal." Section V.C, "Containment Isolation Components," of the SRP-LR recognizes the grouping, stating, "The system consists of isolation barriers in lines for BWR and PWR nonsafety systems such as the plant heating, waste gas, plant drain, liquid waste, and cooling water systems."

The penetrations allow the passage of required fluids across the containment boundary to support the functions of a system. The component intended function is to provide a barrier between fission products released inside the containment and the outside environment. This is a safety function that must also be met for the nonsafety related systems that penetrate the containment. Therefore, the containment isolation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

In Table 2.3.2-2 of the LRA, the applicant identified the containment isolation component types that are within the scope of license renewal and subject to an AMR, including bolting, piping, and valves.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and UFSAR Sections 5.2.4 and 5.4 to determine whether the applicant identified the containment isolation system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting the review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4 (a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

The staff found that those portions of the containment isolation system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, that the applicant identified them as such in LRA Section 2.3.2.2, and that LRA Table 2.3.2-2 includes the containment isolation system components that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.2.3 Conclusion

During its review of information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the containment isolation system. Therefore, the staff concludes that the applicant adequately identified the containment isolation system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the containment isolation system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Emergency Core Cooling

2.3.2.3.1 Summary of Technical Information in the Application

In Section 2.3.2.3 of the LRA, the applicant described the ECCS. The ECCS automatically delivers cooling water to the reactor core in the event of a LOCA. This limits the fuel clad temperature, thereby ensuring that the core will remain substantially intact and in place with its essential heat transfer geometry preserved. For the rupture of a steamline or feedwater line and the associated rapid heat removal from the core, the ECCS adds shutdown reactivity so that there is no consequential damage to the RCS and the core remains intact and in place.

The ECCS includes the safety injection (SI) system (including the accumulators), the RHR system, and portions of the chemical and volume control system (CVCS). The applicant evaluated the RHR spray header components with the containment spray system in Section 2.3.2.1 of the LRA. The portions of the CVCS evaluated with the ECCS for license renewal are the two centrifugal charging pumps and the piping and components used for safety injection. Section 2.3.3.5 of the LRA evaluates the remainder of the CVCS.

The RHR system is also used for normal shutdown cooling. Each train of the RHR system can remove sensible heat from the core while cooling down the plant.

The following portions of the ECCS support the requirements of 10 CFR 50.48:

- those portions of the RHR system required for removal of decay heat from the core to achieve and maintain safe shutdown
- the centrifugal charging pumps (which provide RCS makeup)
- components that provide manual isolation capability for the accumulators following a fire

Therefore, the ECCS is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

In Table 2.3.2-3 of the LRA, the applicant identified the ECCS component types that are within the scope of license renewal and subject to an AMR, including bolting, filter housing, flex hose, heat exchanger (bonnet), heat exchanger (shell), heat exchanger (tubes), heater housing (boron injection tank heater), manifold (piping), orifice, piping, pump casing, strainer housing, tank (including accumulators), thermowell, tubing, and valve.

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 and CNP UFSAR Sections 6.1 and 6.2 to determine whether the applicant identified the ECCS components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that it did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that no passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) were omitted.

In reviewing LRA Section 2.3.2.3, the staff identified areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued an RAI concerning the specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAI and the applicant's related response.

RAI 2.3.2.3-1

The UFSAR states that screen assemblies and vortex suppressors are used in the containment sump which provides water for the ECCS recirculation phase. One of the intended functions is to protect the ECCS pumps from debris and cavitation caused by a harmful vortex following an LOCA. Although LRA Table 2.4-1 lists the screens (fine and coarse) as subject to an AMR, it does not identify the vortex suppressors and their intended function, which should also require an AMR. In RAI 2.3.2.3-1, the staff requested that the applicant submit a clarification.

In its response dated May 20, 2004, the applicant stated that the CNP containment recirculation sump design does not employ vortex suppressors to prevent cavitation from vortexing. The fine and coarse screens listed in LRA Table 2.4-1 serve as flow strainers and mitigate vortex formation by equalizing local velocity differences. The containment recirculation sump design provides sufficient flow area over the trash curb ahead of the sump and adequate net positive suction head for the RHR and containment spray pumps to operate in the recirculation mode. The water level in the sump at the time of switchover from the injection phase to the recirculation phase has been established to ensure sufficient submergence to preclude vortexing or air entrainment. Additionally, the applicant stated that CNP analyses demonstrate that water inventory delivered or released to the containment from the RWST, ice melt, RCS, and safety injection accumulators ensures that the minimum containment recirculation sump level is sufficient to preclude vortex formation in the suction flow to the ECCS and containment spray system pumps.

Based on its review, the staff finds the applicant's response to RAI 2.3.2.3-1 acceptable because the applicant justified why the component does not meet the scoping and screening criteria outlined in 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) and as such is not required to be within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.2.3-1 is resolved.

2.3.2.3.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI response the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the components of the ECCS. Therefore, the staff concludes that the applicant adequately identified the ECCS SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the ECCS SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Containment Equalization/Hydrogen Skimmer System

2.3.2.4.1 Summary of Technical Information in the Application

In Section 2.3.2.4 of the LRA, the applicant described the containment equalization/hydrogen skimmer (CEQ) system. The CEQ system functions postaccident, reducing pressure in the containment and redistributing hydrogen gas from pocketed areas to the general containment volume. These functions are the primary safety intended functions of this system. Therefore, the CEQ system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

The system consists of two redundant independent systems that include fans, backdraft dampers, valves, piping, and ductwork.

In Table 2.3.2-4 of the LRA, the applicant identified the CEQ component types that are within the scope of license renewal and subject to an AMR, including bolting, damper housing, ductwork, fan housing, heat exchanger, piping, and valve.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 and CNP UFSAR Section 5.5 to determine whether the applicant identified the CEQ system components within the scope of license renewal and subject to an AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.3.

In conducting the review, the staff reviewed the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those CEQ components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff found that those portions of the CEQ system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in LRA Section 2.3.2.4, and that the CEQ system components that are subject to an AMR in accordance with 10CFR 54.4(a) and 10 CFR 54.21(a)(1) are included in LRA Table 2.3.2-4. The staff did not identify any omissions.

2.3.2.4.3 Conclusion

During its review of information provided in the LRA, license renewal drawings, and licensing-basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the CEQ system. Therefore, the staff concludes that the applicant has adequately identified the CEQ system's SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the CEQ system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In Section 2.3.3 of the LRA, the applicant identified the following auxiliary system SCs that are subject to an AMR for license renewal:

- spent fuel pool
- essential service water
- component cooling water
- compressed air
- chemical and volume control
- heating, ventilation, and air conditioning
- fire protection
- emergency diesel generator
- security
- postaccident containment hydrogen monitoring
- miscellaneous systems within scope for 10 CFR 54.4(a)(2)
- miscellaneous systems

2.3.3.1 Spent Fuel Pool

2.3.3.1.1 Summary of Technical Information in the Application

In Section 2.3.3.1 of the LRA, the applicant described the spent fuel pool (SFP). The SFP system maintains adequate water inventory for shielding and prevents criticality of the stored fuel. The SFP itself (the SFP walls including the stainless steel liner, gate, and racks that support the fuel) provides the inventory maintenance function. The applicant evaluated these with the auxiliary building structural components in Section 2.4 of the LRA. The racks and the neutron absorber (boral) complete the function of preventing criticality by storage rack geometry in the SFP and the new fuel vault. The applicant evaluated the neutron absorber as part of the SFP system in this section of the LRA.

Section 2.3.2.2 of the LRA evaluates components providing containment isolation (fuel transfer tube).

Section 2.3.3.6 of the LRA evaluates the portion of the SFP ventilation subject to an AMR as the fuel handling area exhaust system.

In accordance with 10 CFR 54.4(a)(2), nonsafety related component types in the SFP system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Nonsafety related component types that require an AMR for 10 CFR 54.4(a)(2) are in the SFP cooling portion of the system. Section 2.3.3.11 of the LRA includes the evaluation of SFP cooling.

As its primary safety intended function, the SFP system maintains adequate water inventory for shielding and prevents criticality of the stored fuel. The system also provides a containment isolation function. The system is included within the scope of license renewal because of the potential for spatial interactions with safety related equipment. Therefore, the SFP system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2).

In Table 2.3.3-1 of the LRA, the applicant identified the SFP component types that are within the scope of license renewal and subject to an AMR, including SFP poison.

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 and CNP UFSAR Section 9.7 to determine whether there is reasonable assurance that the applicant identified the SFP system 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). In LRA Section 2.3.3.11, the applicant separately compiled scoping and screening results for all components with intended functions that were within the scope of license renewal based on the criterion of 10 CFR 54.4(a)(2). The staff reviewed those components for the SFP system in Section 2.3.3.11 of this SER. The staff conducted its review in accordance with guidance of SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning the specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.1-1

Section 2.3.3.1, "Spent Fuel Pool," of the LRA states, "The primary safety intended function of the SFP system is to maintain adequate water inventory for shielding and to prevent criticality of the stored fuel."

By letter dated February 4, 1992, which responded to a staff request for information regarding the qualification of makeup water sources, the applicant stated that makeup water to the SFP can be obtained from several reliable, permanently installed sources. Further, the applicant stated that with these diverse sources, makeup water will be readily available in the event of loss of SFP cooling.

In the associated SE dated January 14, 1993, the staff stated that the SFP meets the design criteria of Regulatory Guide 1.13 which requires a diversity of make up water sources to the SFP. Previously, another SE accepted the use of the CVCS hold-up tanks as the Seismic Category I source of make up water to the SFP.

The license renewal drawing of the SFP does not show this source of makeup water from the CVCS hold-up tanks to the SFP or any other makeup water source as being subject to an AMR. The staff requested that the applicant justify the exclusion of the piping and components linking the makeup water source from the CVCS hold-up tanks and at least one other makeup water source to the SFP from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(1)(iii) and 10 CFR 54.21(a)(1).

In its responses, dated May 7, 2004 and September 2, 2004, the applicant stated that the make-up water piping from the CVCS hold-up tanks to the SFP is not currently classified as Seismic Class I. Consequently, these piping and components are not subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(1)(iii). The applicant added that this response is in agreement with its responses to the staff's request for additional information pertaining to License Amendments 13, 32, 58, and 74.

In response to the staff's request for identifying a source of makeup water to the SFP within the scope of license renewal, the applicant in its supplemental response to RAI 2.3.3.1-1 stated that the fire water system will be credited for providing makeup water to the SFP in the event that no other sources are available and makeup water is required.

Further, the applicant stated that the FP system is capable of delivering water to the SFP via multiple fire hose stations in excess of the maximum calculated SFP boil-off rate should the SFP cooling system become unavailable. The fire water hoses and associated supply piping are included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3) and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

However, the fire water hoses alone do not provide the diversity of makeup water sources specified within the licensing basis of the facility. The ability to maintain adequate water inventory in the event of a loss of SPF cooling assures that an offsite release comparable to the 10 CFR Part 100, "Reactor Site Criteria," limits would be prevented. In response to staff inquiries regarding the qualification of makeup water sources, the applicant previously credited the diversity of makeup water sources to assure that makeup water would be available following events that cause a loss of SFP cooling in lieu of identifying a makeup water source qualified as seismic Category I. Therefore, during a subsequent telephone conference on October 27, 2004 between the NRC staff and the applicant, the staff asked that the applicant provide other sources of makeup water in addition to the FP system that is included within the scope of license renewal to satisfy the requirements of 10 CFR 54.4(a)(2).

In response to the staff request for identifying a source of makeup water to the SFP other than the fire water hoses, the applicant, in a letter dated November 18, 2004, stated that it will additionally credit refueling water from either unit's refueling storage tank (RWST) as a second diverse in-scope source of makeup water to the SFP. The applicant stated that the capacity of this makeup source has been previously evaluated and determined to exceed the maximum calculated SFP boil-off rate.

The applicant added that the additional components included in the license renewal scope are depicted on license renewal drawing LRA-12-5136 and include those stainless steel components (such as valves, pump, orifices, demineralizer, filters, piping, and pipe appurtenances) in the flow path from the RWST isolation valves to the SFP. The makeup flow path from the RWST isolation valves (1-SI-183 and 2-SI-184) includes the refueling water purification pump and the spent fuel pit filter and terminates at the SFP. Neither the spent fuel pit demineralizer nor the refueling water purification filter is in the makeup flow path; however, these components are included because they provide a pressure boundary function. The components in this flow path are included in the scope of license renewal in accordance with the 10 CFR 54.4(a)(2) scoping criterion; however, they have not been highlighted on the license renewal drawing.

Further, the first paragraph of LRA Section 2.3.3.11, Spent Fuel Pool Cooling, on Page 2.3-82 is modified as provided below:

> The purpose of spent fuel pool cooling is to remove, from the spent fuel pool, the heat generated by stored fuel elements. The components of the CNP spent fuel pool cooling provide no 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3) intended functions. The maintenance of pool inventory, which assures cooling, is provided by the spent fuel pit as discussed in Section 2.3.3.1. Those components in the flow path from the RWST isolation valves (1-SI-183 and 2-SI-184) to the SFP are credited as one of the diverse sources of makeup water to the SFP, and perform a 10 CFR 54.4(a)(2) intended function. The spent fuel pool is shared by the two units. The design incorporates two separate cooling trains sharing a common return to the spent fuel pool. Piping is arranged so that failure of any pipe does not drain the spent fuel pool below the top of the stored fuel elements.

The staff finds the applicant response to RAI 2.3.3.1-1 in the September 2, 2004 and November 18, 2004 letters to be acceptable on the basis that the applicant adequately identified the non safety related makeup water sources to the SFP system that are within the scope of license renewal because they functionally support the SFP system's intended function. Therefore, the staff's concerns described in RAI 2.3.3.1-1 are resolved.

RAI 2.3.3.1-2

Section 2.1.2.1.2 of the LRA states, "licensing renewal drawings were created by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an aging management review."

The staff requested that the applicant confirm that the system components marked on license renewal drawings depict all the components within the SFP system that perform an intended function (*i.e.*, within the system evaluation boundary).

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are within the scope of license renewal and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Section 2.4.2 of the LRA discusses structures depicted on license renewal drawing LRA-12-5136 that perform an intended function. Table 2.4-2 of the LRA lists these in the structure/component/commodity types "spent fuel pit steel (including swing gate, attachments, liner, and fuel racks)," "spent fuel pit walls and slab," and "fuel transfer canal." Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators. License renewal drawing LRA-12-5136 does not depict any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.1-2 acceptable. The applicant adequately described the process for identifying system components that are subject to an AMR on license renewal drawings. The applicant described as necessary those components that meet the requirements of 10 CFR 54.4(a) but are not shown on the license renewal drawings and discussed the alteration of the system evaluation boundaries. Therefore, the staff confirmed that the applicant evaluated all the components with intended functions for an AMR, including those components at license renewal system boundaries and interfaces with other systems. The applicant identified as necessary those components within the system evaluation boundary for a license renewal system that were not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.1-2 is resolved.

2.3.3.1.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the SFP system. Therefore, the staff concludes that the applicant adequately identified the SFP SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SFP system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Essential Service Water

2.3.3.2.1 Summary of Technical Information in the Application

In Section 2.3.3.2 of the LRA, the applicant described the essential service water (ESW) system. The ESW system supplies cooling water from the ultimate heat sink to essential heat loads, including the following components:

- component cooling heat exchangers
- containment spray heat exchangers
- emergency diesel generators
- auxiliary feedwater pumps
- control room air conditioners (coolers and chiller condensers)
- auxiliary feedwater pump enclosure coolers

The ESW system is an emergency water supply for the emergency diesel generator (EDG) jacket water surge tank. The Unit 1 east ESW train is cross-connected to the Unit 2 west header, and the Unit 1 west train is cross-connected to the Unit 2 east header. In addition to its primary intended function of providing cooling water, the ESW system is a backup suction source for the auxiliary feedwater pumps for use when the condensate storage tank (CST) is unavailable as a source of supply. The Appendix R safe-shutdown analysis credits the ESW system unit cross-tie, so the system is required for compliance with the criteria of 10 CFR 50.48.

In accordance with 10 CFR 54.4(a)(2), nonsafety related portions of the system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Nonsafety related component types in the ESW system that require an AMR pursuant to 10 CFR 54.4(a)(2) are in the auxiliary building and screenhouse and consist of bolting, valves, tubing, and piping. The environment and materials are the same in safety related and nonsafety related portions of the system. The AMR results in Table 3.3.2-2 of the LRA apply to the portions of the system requiring an AMR pursuant to 10 CFR 54.4(a)(2).

The ESW system is the safety related source of cooling to ESF equipment. The ESW system also provides cooling to Appendix R safe-shutdown equipment. Nonsafety related portions of the system must maintain mechanical and structural integrity so that nearby safety related equipment is not adversely affected. Consequently, the system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.3.3-2 of the LRA, the applicant identified the ESW component types that are within the scope of license renewal and subject to an AMR, including bolting, detector well, expansion joint, fittings, flex hose, manifold (piping), orifice, piping, pump casing, strainer, strainer housing, thermowell, tubing, and valve.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 and CNP UFSAR Section 9.8.3 to determine whether there is reasonable assurance that the applicant identified the ESW system 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 staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with Section 2.3 guidance of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.2 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.2-1

Table 2.3.3-2 of the LRA lists tubing in the ESW as subject to an AMR. However, the ESW license renewal drawings do not identify tubing. The staff asked the applicant to identify the ESW tubing that is within the scope of license renewal and subject to an AMR.

In its response dated May 7, 2004, the applicant stated that instruments typically include tubing from the process piping to the instrument, although the LRA drawings do not always show this tubing. The license renewal drawings highlight entire instrument lines between the main process piping up to the instrument indicating that they are subject to an AMR. Instrument lines typically include tubing as a part of the routing to the instrument, even though it is not specifically identified as tubing on the drawing. In LRA Table 2.3.3-2, the "tubing" entry represents instrument tubing, and the "piping" entry represents process and/or instrument piping. The table lists both component types to describe the complete passive mechanical pressure boundary up to the instruments. Table 3.3.2-2 of the LRA provides the AMR results for the tubing.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.2-1 acceptable because the applicant identified and evaluated ESW tubing in the LRA. Therefore, the staff's concern described in RAI 2.3.3.2-1 is resolved.

RAI 2.3.3.2-2

License renewal drawings of the ESW system identify "auto vent auxiliary building ventilation system" components shown at various locations to be within the scope of license renewal and subject to an AMR. However, this component group is not listed in Table 2.3.3-2 as being subject to an AMR. The applicant was asked to include the Auto Vent VA component group in Table 2.3.3-2 or justify the exclusion of this group from the table.

In its response dated May 7, 2004, the applicant stated that it included the auto vent VA components under the component type "valve" and included them in the AMR of the ESW system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.2-2 acceptable because Table 2.3.3-2 of the LRA represents the auto vent VA components and they are evaluated for an AMR. Therefore, the staff's concern described in RAI 2.3.3.2-2 is resolved.

RAI 2.3.3.2-3

Section 2.3.3.2 of the LRA states that the license renewal drawings do not indicate components that are only within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). This section also states, "nonsafety-related component types in the ESW system that require an AMR for 10 CFR 54.4(a)(2) are in the auxiliary building and screenhouse and consist of bolting, valves, tubing and piping."

The staff asked the applicant to clarify whether all the bolting, valves, tubing, and piping in the auxiliary building and screenhouse are within scope and subject to an AMR in accordance with 10 CFR 54.4(a)(2) and 10 CFR 54.21(a)(1). If not, the staff asked the applicant to identify the components that are within scope and subject to an AMR.

The 10 CFR 54.4(a)(2) identification process, as described in the applicant's response to RAI 2.3.3.11-2, designates nonsafety-related systems and components with the potential for spray or leakage that could prevent safety-related systems and components from performing their required safety function. Conservatively, the applicant determined all nonsafety-related components containing liquid or steam located in the auxiliary building and screenhouse to be subject to an AMR unless no safety-related equipment is in the area.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.2-3 acceptable because the applicant's responses to RAI 2.3.3.11-2 adequately described the components in the auxiliary building and screenhouse that are subject to an AMR in accordance with 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.2-3 is resolved.

RAI 2.3.3.2-4

Section 2.1.2.1.2 of the LRA states, "licensing renewal drawings were created by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an aging management review."

The staff requested that the applicant confirm that the system components marked on the license renewal drawing depict all the components within the ESW system that perform an intended function (*i.e.*, within the system evaluation boundary).

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings include all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are within the scope of license renewal and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators. The license renewal drawings do not include any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.2-4 acceptable. The applicant adequately described the process for identifying system components on license renewal drawings that are subject to an AMR. The applicant described as necessary the components that meet the requirements of 10 CFR 54.4(a) but are not shown on the license renewal drawings and discussed the alteration of the system evaluation boundaries. Therefore, the staff confirmed that the applicant evaluated all the components with intended functions for an AMR, including those components at license renewal system boundaries and interfaces with other systems. The applicant identified as necessary those components within the system evaluation boundary for a license renewal system that are not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.2-4 is resolved.

2.3.3.2.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the ESW system. Therefore, the staff concludes that the applicant adequately identified the ESW SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the ESW system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.3 Component Cooling Water

2.3.3.3.1 Summary of Technical Information in the Application

In Section 2.3.3.3 of the LRA, the applicant described the CCW system. The CCW system provides cooling to potentially radioactive heat sources and ensures that leakage of radioactive fluid from those heat sources is contained within the plant. The CCW system is an intermediate, closed-loop system between heat sources and the ultimate heat sink (Lake Michigan). Components cooled by the CCW system are split between two redundant safeguards trains and a miscellaneous service train that may be supported by either safeguards train. The CCW system removes heat from the RCS, the SFP, and various plant heat exchangers and components. The CCW system then transfers that heat to the ESW system.

In accordance with 10 CFR 54.4(a)(2), nonsafety related component types in the CCW system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Nonsafety related component types that require an AMR for 10 CFR 54.4(a)(2) are in the auxiliary building and consist of the following:

- bolting
- tanks
- eductors
- valves
- manifolds
- tubing
- piping

The applicant addressed nonsafety related heat exchangers supplied with CCW as required with the systems they cool. The environment and materials are the same in safety related and nonsafety related portions of the system. The AMR results in Table 3.3.2-3 of the LRA apply to the portions of the CCW system requiring an AMR for 10 CFR 54.4(a)(2).

The CCW system is the safety related source of cooling to ESF equipment. The CCW system also provides cooling to Appendix R safe-shutdown equipment. Portions of the system without a safety function must maintain mechanical and structural integrity so that nearby safety related equipment is not adversely affected. Consequently, the CCW system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In LRA Table 2.3.3-3, the applicant identified the CCW component types that are within the scope of license renewal and subject to an AMR, including bolting, detector well, expansion joint, fittings, heat exchanger, heat exchanger (bonnet), heat exchanger(shell), heat exchanger (tubes), manifold (piping), orifice, piping, pump casing, strainer - tee, tank, thermowell, tubing, and valve.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and CNP UFSAR Section 9.5 to determine whether there is reasonable assurance that the applicant identified the CCW system components within the scope of license renewal and subject to an AMR, in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of the LRA Section 2.3.3.3 identified areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1) were properly applied. The following describes the staff's RAIs and the applicant's responses.

RAI 2.3.3.3-1

The following items are shown on the license renewal drawings as within the scope of license renewal and subject to an AMR. However they are not listed in Table 2.3.3-3, "Component Cooling Water (CCW) System Components Subject to Aging management Review." The staff requested that the applicant explain why these components are not listed in Table 2.3.3-3 as components subject to an AMR.

(a) Upper and lower bearing oil coolers shown on the license renewal drawings LRA-1-5135D and LRA-2-5135D

(b) External pipe coils shown on the license renewal drawings LRA-1-5135E and LRA-2-5135E

In its response dated May 7, 2004, the applicant stated the following:

> (a) Upper bearing oil coolers are included in LRA Table 2.3.3-3 under the component types "Heat exchanger (shell)" and "Heat exchanger (tubes)." Lower bearing oil coolers are included in LRA Table 2.3.3-3 under the component type, "Heat exchanger."
>
> (b) External pipe coils are included in LRA Table 2.3.3-3 under the component type, "Heat exchanger."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-1 acceptable, because the bearing oil coolers and pipe coils are represented on Table 2.3.3-3 and are evaluated for an AMR as indicated in Table 3.3.2-3. Therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

RAI 2.3.3.3-2

LRA Table 2.3.3-3 lists tubing, strainer-tee, and expansion joint as component groups that are subject to an AMR. However, the staff is not able to identify them on the license renewal drawings as components subject to an AMR. The staff requested the applicant to identify CCW system tubing, stainer-tees, and expansion joints that are subject to an AMR and provide justification for those that are not subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the CCW system instrument tubing is subject to an AMR based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3). The instrument tubing is highlighted on license renewal drawings by highlighting the entire line up to each instrument, including the tubing between the process piping and the instrument. Component types "tubing" and "piping" represent the tubing. The LRA table also represents nonsafety-related CCW system instrument tubing subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2).

Additionally, CCW strainer-tees subject to an AMR are highlighted on the drawings . Since they have specific component numbers on the drawings, they were specified as components subject to an AMR.

CCW expansion joints subject to an AMR are highlighted on the drawings. Since they have specific component numbers on the drawings, they were specified as components subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-2 acceptable because the components in question have been adequately identified and represented in the LRA tables and are evaluated for an AMR. Therefore, the staff's concern described in RAI 2.3.3.3-2 is resolved.

RAI 2.3.3.3-3

Section 2.3.3.3 of the LRA lists eductors as nonsafety-related components in the auxiliary building that require an AMR in accordance with 10 CFR 54.4(a)(2). However, the license renewal drawing for the CCW system does not show eductors, nor does LRA Table 2.3.3-3 list them as components subject to an AMR. The staff requested the applicant identify the eductors in the CCW system and explain why LRA Table 2.3.3-3 does not list them as components subject to an AMR.

In its response, dated May 7, 2004, the applicant stated that the CCW chemical mixing tank eductor shown on drawing LRA-1-5135 requires AMR for 10 CFR 54.4(a)(2) only. LRA Section 2.1.2.1.2 states that components that are within the scope of license renewal based solely on the criterion of 10 CFR 54.4(a)(2) are not indicated on LRA drawings. LRA Table 2.3.3-3 only includes components that are subject to an AMR for 10 CFR 54.4 (a)(1) or 10 CFR 54.4 (a)(3). LRA Section 2.3.3.11 describes the CCW system as a Group I system (*i.e.*, the material and environments are the same in the portion of the system meeting the criteria of 10 CFR 54.4(a)(2) as for those portions meeting the criteria of 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3)). Therefore, AMPs for the environmental and material combinations identified in LRA Table 3.3.2-3 will manage aging for the eductor.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-3 acceptable because it stated that eductors in the CCW system are subject to an AMR. In addition, the AMP identified in LRA Table 3.3.2-3 will manage the aging effects for the CCW eductors. Therefore, the staff's concern described in RAI 2.3.3.3-3 is resolved.

RAI 2.3.3.3-4

License renewal drawings show portions of the CCW system piping between the license renewal boundary flags leading to and from the seal water heat exchangers and to and from the letdown heat exchangers, including the heat exchangers tubes and shells, as not subject to an AMR. However, parts of the seal water heat exchanger and letdown heat exchangers (heat exchanger channel, tubesheet, and tube side nozzles) that are within the CVCS license renewal boundary are shown as subject to an AMR. The staff requested the applicant to explain why it excluded these portions of the CCW system from an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response dated May 7, 2004, the applicant stated that the CVCS seal water and letdown heat exchangers contain reactor coolant on the tube side and CCW on the shell side. One CVCS intended function is to maintain the system pressure boundary to contain reactor coolant fluid. Consequently, the tube side of these heat exchangers requires aging management. Heat transfer is not a 10 CFR 54.21(a)(1) intended function for these heat exchangers. Consequently, CCW supply to the seal water and letdown heat exchangers is not required, based on the criteria of 10 CFR 54.21(a)(1). In the response to RAI 2.3.3.3-5, the applicant provided additional discussions that support the basis for the CCW system scope boundaries with regard to CCW inventory loss.

In conclusion, the seal water and letdown heat exchangers are required for the CVCS pressure boundary intended function only. The CCW side of the heat exchangers does not perform a

10 CFR 54.21(a)(1) intended function and consequently is not marked on the license renewal drawings.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-4 acceptable, because it explained that the CCW side of the seal water and letdown heat exchangers does not have a pressure boundary intended function, thus it is excluded from being subject to an AMR in accordance with the requirement of 10 CFR 54.21(a)(1). Therefore, the staff's concern described in RAI 2.3.3.3-4 is resolved.

RAI 2.3.3.3-5

The boundary of the portion of the CCW system that is subject to an AMR ends at valves that are shown on the license renewal drawings as normally open. Failure of the downstream piping may affect the pressure boundary intended function. However, Section 2.3.3.3 of the LRA does not discuss why this approach is acceptable. The staff asked the applicant to provide additional information to support the basis for this determination. For example, the staff asked the applicant to discuss the steps in the procedures for identifying the locations of breaks and closing the valves, the amount of time required to complete these steps, and the consequences on system inventory if the valves are not closed.

In its response dated May 7, 2004, the applicant stated that the CCW system is an intermediate closed-loop system between heat sources and the ultimate heat sink. The applicant further described the functions of the CCW system as meeting the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

The applicant stated that the normally open valves in question are associated with the CCW miscellaneous services header and that this is acceptable based on safety significance, system functional requirements, and postulated failure modes. The applicant provided an evaluation of the affected loads on this header, along with the effects of the header's loss of inventory and its ability to perform system intended functions.

Additionally, the applicant described the CCW system monitoring instrumentation for loss of inventory. It described the actions to diagnose and mitigate the loss of inventory, based on approved procedures. The applicant concluded that motor-operated main header isolation valves provide the primary isolation boundaries for the CCW system miscellaneous services header, and for a leak in a nonsafety-related branch load, the main header isolation valves would be closed from the control room to isolate the leak minutes after alarm receipt and subsequent diagnosis of the failure.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-5 acceptable because the applicant's explanations for selecting the system boundaries are appropriate with respect to the scoping methodology. Therefore, the staff's concerns described in RAI 2.3.3.3-5 are resolved.

RAI 2.3.3.3-6

Section 2.1.2.1.2 of the LRA states, "licensing renewal drawings were created by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an aging management review."

The staff requested that the applicant confirm that system components marked on the CCW license renewal drawings depict all the mechanical components that perform an intended function within the CCW system evaluation boundary.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are within the scope of license renewal and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). The AMRs for the structural elements of the CCW containment penetrations, shown on license renewal drawings, are grouped with the structural review in LRA 2.4.1. The CCW system includes components with a potential for 10 CFR 54.4(a)(2) functional failure, as well as spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-6 acceptable. The applicant adequately described the process for identifying system components that are subject to an AMR on license renewal drawings. The applicant described as necessary the components that meet the requirements of 10 CFR 54.4(a) but are not shown on the license renewal drawings and discussed the alteration of the system evaluation boundaries. Therefore, the staff confirmed that it evaluated all the components with intended functions for an AMR, including those components at license renewal system boundaries and interfaces with other systems. The applicant identified as necessary those components within the system evaluation boundary for a license renewal system that are not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.3-6 is resolved.

RAI 2.3.3.3-7

Section 2.1.2.1.2 of the LRA states that the applicant created license renewal drawings by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an AMR. Components that are within the scope of license renewal based solely on the criteria of 10 CFR 54.4(a)(2) are not generally indicated on the drawings but are described in Section 2.3 and listed in Table 3.3.2-11 of the LRA.

Pursuant to 10 CFR 54.21(a)(1), the applicant must identify and list those SCs subject to an AMR. The staff's position is that the applicant did not satisfy this requirement because the components of the CCW system meeting 10 CFR 54.4(a)(2) are neither listed nor identified on drawings. The applicant included these components as "component types," instead of as individually listed components. The staff requested that the applicant confirm that the CCW system components marked on license renewal drawings depict all the components within the CCW system that meet the requirements of 10 CFR 54.4(a)(2). If not, the staff requested the applicant to provide a list of these components that are not marked on license renewal drawings or provided revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that, since the potential for a 10 CFR 54.4(a)(2) functional failure concern exists, clarification of the license renewal drawings for the CCW miscellaneous services header components that are within the scope of license renewal and subject to an AMR is warranted. The applicant adequately identified those portions of the CCW miscellaneous services header that meet the 10 CFR 54.4(a)(2) criterionon drawings and in tables.

In its response to RAI 2.3.3.11-2, dated May 7, 2004 and September 2, 2004, the applicant discussed the scoping and screening of components meeting the 10 CFR 54.4(a)(2) criterion. These components include nonsafety-related components containing liquid or steam located in the containment building, auxiliary building, screenhouse, and the portion of the turbine building that contains the auxiliary feedwater pumps unless no safety related equipment is in the area.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-7 acceptable because the applicant adequately addressed questions concerning the scoping and screening of components meeting the requirements of 10 CFR 54.4(a)(2) for the CCW system. Therefore, the staff's concerns described in RAI 2.3.3.3-7 are resolved.

2.3.3.3.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the CCW system. Therefore, the staff concludes that the applicant adequately identified the CCW SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CCW system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Compressed Air

2.3.3.4.1 Summary of Technical Information in the Application

In Section 2.3.3.4 of the LRA, the applicant described the compressed air (CA) system. This section covers the components in the CA system, which includes both the control air (CTRLA) and plant air (PA) systems. This section also includes the reactor nitrogen (N2) system, since portions of the N2 system provide a backup supply to the CA system.

<u>Control Air</u>. The CTRLA system provides a continuous supply of dry, oil-free, filtered compressed air to pneumatic instruments and air-operated valves and dampers for various process systems. Compressed CTRLA is supplied to components in the turbine building, auxiliary building, and containment. Major components of the CTRLA system include the following:

- control air compressors
- wet control air receivers
- prefilters
- air dryers
- afterfilters
- dry control air receivers
- associated distribution piping and valves

The CTRLA system is part of the CA system described in the UFSAR. The CTRLA system has a safety intended function of providing the CTRLA required to support the operation of a limited number of safety related components. It also has a containment isolation function. Control air is supplied to components required to operate for the Appendix R safe-shutdown analysis and for the SBO event. Therefore, this system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Plant Air. The PA system provides CA throughout the plant for service usage and ice condenser outage support. CA is supplied to CNP, Units 1 and 2, through an air distribution system located in the turbine building, auxiliary building, containment, and screenhouse building. This distribution system consists of a shared PA ring header extending throughout the turbine building, a pair of parallel PA headers in the auxiliary building, and a PA header in each containment. One PA compressor, PA receiver, and PA aftercooler is located in each unit. The PA system is part of the CA system described in the UFSAR.

Because some components of the PA system are associated with containment isolation, the PA system is within the scope of license renewal based on 10 CFR 54.4(a)(1). The system provides no other function that meets the scoping criteria for license renewal.

Reactor Nitrogen. The N2 system provides nitrogen for purging and blanketing tanks and equipment in the RCS and nuclear auxiliary systems for both Units 1 and 2. The N2 system also supplies nitrogen to the ECCS accumulators and to the steam generator power-operated relief valves (backup supply).

The backup nitrogen supply to the steam generator power-operated relief valves supports operation of these valves for a controlled cooldown for the Appendix R safe-shutdown analysis. Therefore, the system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(3).

Because some components of the N2 system are associated with containment isolation, the N2 system is within the scope of license renewal based on 10 CFR 54.4(a)(1). Section 2.3.2.2 of the LRA evaluates the containment isolation components for the N2 system. Section 2.3.2.3 of the LRA evaluates the nitrogen supply to the ECCS accumulators.

In Table 2.3.3-4 of the LRA, the applicant identified the CA component types that are within the scope of license renewal and subject to an AMR, including bolting, fittings, flex hose, piping, tank, tubing, and valve.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and CNP UFSAR Section 9.8.2 to determine whether there is reasonable assurance that the applicant identified the CA system 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 staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of the LRA Section 2.3.3.4 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.4-1

The staff asked the applicant to clarify whether the components listed in Table 2.3.3-4 are subject to an AMR. If not, in RAI 2.3.3.4-1, summarized below, the staff asked the applicant to justify the exclusion of these components from an AMR in accordance with the requirements of 10 CFR 54.21(a)(1):

(a) License renewal drawings show pressure regulators within the scope of license renewal and subject to an AMR: LRA-1-5120R, and LRA-2-5120R and LRA-1-5120S and LRA-2-5120S. However, housings of these regulators, which are passive and long-lived, are not specifically listed as components subject to an AMR in Table 2.3.3-4.

(b) License renewal drawings LRA-1-5120R, LRA-2-5120R, LRA-1-5120S, and LRA-2-5120S show components MRV-223-VB1, MRV-223-VB2, MRV-233-VB1, MRV-233-VB2, MRV-213-VB1, MRV-213-VB2, MRV-243-VB1, and MRV-243-VB2 as within the scope of license renewal and subject to an AMR. Also, the applicant was asked to identify these components because they are not identified either on the standard symbol drawings or the control air system standard symbol drawing.

(c) License renewal drawing LRA-12-5118B shows an electronic pneumatic transducer within the scope of license renewal and subject to an AMR. However, the pressure retaining boundary of this component, which is passive and long-lived, is not specifically listed as a component subject to an AMR in Table 2.3.3-4.

In its response dated May 7, 2004, the applicant stated the following:

> (a) Pressure retaining portions of pressure regulators (or pressure control valves) shown as subject to an AMR on drawings LRA-l-5120R, LRA-2-5120R. LRA-1-5120S and LRA-2-5120S are included in component type "valve" listed in LRA Table 2.3.3-4.
>
> (b) Components, N4RV-233-VBI. MRV-223-VB2, MRV-233-VBI, MRV-233-VB2, MRV-213-VB1, MRV-213-VB2, MRV-243-VBI, and MRV-243-VB2 are steam generator power operated relief valve (PORV) upper and lower pneumatic volume boosters used for manual local operation of the steam generator PORVs. Pressure retaining portions of these components are included in component type "valve" listed in LRA Table 2.3.3-4.
>
> (c) Pressure retaining portions of electronic pneumatic transducers 2-GRV-354 on drawing LRA-12-5118B, and 1-GRV-354 are included in component type "Valve" listed in LRA Table 2.3.3-4.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.4-1 acceptable because it adequately explains that the pressure retaining portions of the pressure regulators, power operated relief valves, and electronic pneumatic transduces are included in the component type "valve" which is listed in Table 2.3.3-4 as a component type subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.3.4-1 are resolved.

RAI 2.3.3.4-2

On license renewal drawings LRA-1-5120R, LRA-2-5120R, LRA-1-5120S, and LRA -2-5120S, components marked as MRV-223, MRV-233, MRV-213, and MRV-243 are shown as excluded from requiring an AMR. However, it appears that these components have pressure boundary intended function. These components are not identified either on the standard symbol drawings or control air system standard symbol drawing. The applicant was asked to identify these components and clarify whether they are passive and long-lived. If so, the applicant was asked to explain why these components are not shown on the drawings and listed in LRA Table 2.3.3-4 as being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response dated May 7, 2004, the applicant stated that components MRV-223, MRV-233, MRV-213, and MRV-243 are the steam generator power-operated relief valves (PORVs). The applicant reviewed the valves in the main steam system, showed them on drawings LRA-I-5105D and LRA-2-5105D as subject to an AMR, and included them in the component type "Valve" listing in LRA Table 2.3.4-2. However, the operators for these valves shown on drawings LRA-I-5120R, LRA-2-5120R, LRA-I-5120S, and LRA-2-5120S are active components and are therefore not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.4-2 acceptable, because it adequately explains that PORVs are subject to an AMR and are included in the "valve" component type listed in LRA Table 2.3.4-2. Furthermore, the applicant justified exclusion of the valve operators from being subject to an AMR as active components. Therefore, the staff's concerns described in RAI 2.3.3.4-2 are resolved.

RAI 2.3.3.4-3

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function because the applicant did not identify the components within the system evaluation boundary in its LRA. The staff must verify this information to effectively review the LRA using the SRP-LR.

The staff requested that the applicant confirm that the system components marked on license renewal drawings for the CA system depict all the components that perform an intended function. If not, the staff asked the applicant to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or provide revised drawings as needed to include the additional components.

In its response, dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function with the exception of structures, active and short-lived components, and those components that are in scope and subject to an AMR based solely on the criterion of 10 CFR 54.4(a)(2). Active components that were screened out, and are therefore not highlighted on flow diagrams, are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10. This includes items such as instrumentation, motors and valve operators.

In the CA system, a number of relief valves on non-safety related piping are identified as safety related on license renewal drawings. These relief valves perform the active function of providing overpressure protection of fail-safe, air-operated valves in the event of a regulator failure. The pressure boundary function is not required to be maintained for these components because they are not in a safety related containment isolation boundary or in a portion of the system with a required backup accumulator. Therefore, an AMR is not required for these relief valves.

Mechanical components in the back-up CA supply to the pressurizer power-operated relief valves are highlighted on license renewal drawings LRA-1-5120D and LRA-2-5120D. The reserve control air tanks are subject to an AMR. However, the air bottles are frequently replaced with new bottles; therefore, these air bottles are not long-lived components, and they do not require an AMR.

Further, the mechanical components in the back-up air supply for the post-accident containment hydrogen monitoring system (PACHMS) are shown on license renewal drawings LRA-1-5120NN and LRA-2-5120KK. The back-up air tanks are frequently replaced with new tanks; therefore these tanks are not long-lived components, and they are not subject to an AMR.

Based on the operating experience, the nonsafety related air components do not pose a hazard to other plant equipment, and cannot adversely affect safety related components due to leakage or spray. As a result nonsafety related components in the CA system that contain dry air or gas do not meet the 10 CFR 54.4(a)(2) criterion, and are not in the scope of license renewal.

The CA system license renewal drawings do not depict any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.4-3 acceptable because it adequately justifies the exclusion of the CA system nonsafety related components from the scope of license renewal and an AMR in accordance with the requirements of 10 CFR 54.4 (a)(2) and 10 CFR 54.21(a)(1), respectively. Therefore, the staff's concerns described in RAI 2.3.3.4-3 are resolved.

2.3.3.4.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the CA system. Therefore, the staff concludes that the applicant adequately identified the CA SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CA system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Chemical and Volume Control

2.3.3.5.1 Summary of Technical Information in the Application

The applicant described the CVCS in Section 2.3.3.5 of the LRA. The CVCS supports the RCS in a variety of ways and has the following functions:

- adjust the concentration of boric acid
- maintain the proper water inventory in the RCS
- provide the required seal water flow for the RCP shaft seals
- process reactor coolant effluent for reuse of boric acid and reactor makeup water
- maintain the proper concentration of corrosion-inhibiting chemicals in the reactor coolant
- maintain the reactor coolant activities within design limits
- provide borated water for safety injection
- fill and hydrostatically test the RCS

The centrifugal charging pumps and piping and components used for SI are evaluated as part of the ECCS, which is described in Section 2.3.2.3 of the LRA. Class 1 piping and associated pressure boundary components in the reactor coolant pressure boundary are evaluated with the RCS, which is described in Section 2.3.1.4 of the LRA.

The CVCS intended functions include the following:

- maintaining the RCS pressure boundary
- providing RCS inventory control
- *providing borated water for reactivity control*
- supporting ECCS injection
- providing RCP seal injection and processing seal leakoff
- providing cross-unit charging to support Appendix R-required safe shutdown of the opposite unit, which includes RCP seal injection, RCS inventory makeup, and reactivity control

In accordance with 10 CFR 54.4(a)(2), nonsafety related portions of the system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Certain nonsafety related component types in the CVCS, including those components that provide RCP seal injection and seal leakoff processing, meet the criteria of 10 CFR 54.4(a)(2). These components are in the auxiliary building and containment. The environment and materials of the components are the same in both the safety related and nonsafety related portions of the system. The AMR results in Table 3.3.2-5 of the LRA apply to the portions of the system requiring an AMR, in accordance with 10 CFR 54.4(a)(2).

The Appendix R safe-shutdown analysis credits the CVCS (including the pump discharge cross-tie) for RCP seal injection, RCS inventory makeup, and reactivity control. The applicant credited CVCS components with minimizing the loss of RCP seal water during an SBO event.

The CVCS is within scope as a safety related system, and portions are within scope as nonsafety related affecting safety related components. Portions of the CVCS are required to support FP requirements and requirements for SBO. Therefore, the CVCS is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.3.3-5 of the LRA, the applicant identified the CVCS component types that are within the scope of license renewal and subject to an AMR, including bolting, filter housing, flow element body, heat exchanger (bonnet), heat exchanger (shell), heat exchanger (tubes), heater housing, level glass gauge, manifold (piping), orifice, piping, piping-spool assembly, pulsation dampener, pump casing, strainer - tee, tank, thermowell, tubing, and valve.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 and CNP UFSAR Section 9.2 using the evaluation methodology described in Section 2.3 of this SER and in accordance with Section 2.3 of the SRP-LR..

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

On the basis of its review, the staff found that the applicant identified those portions of the CVCS that meet the scoping requirements of 10 CFR 54.4(a) and included them within the scope of license renewal in LRA Section 2.3.3.5. The applicant also included the CVCS components that are subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) in LRA Table 2.3.3-5. The staff did not identify any omissions.

2.3.3.5.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the CVCS. Therefore, the staff concludes that the applicant adequately identified the CVCS SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CVCS SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 Heating, Ventilation, and Air Conditioning

2.3.3.6.1 Summary of Technical Information in the Application

This section covers the heating, ventilation, and air conditioning (HVAC) subsystems and components within the scope of license renewal for CNP, with two exceptions. The exceptions include the CEQ system, which is an engineered safeguards system covered in Section 2.3.2 of this SER, and the auxiliary building ventilation and miscellaneous ventilation systems, which are only within scope based on the criteria of 10 CFR 54.4(a)(2) and are discussed in Section 2.3.3.11 of this SER.

Engineered Safety Features Ventilation. The engineered safety features (ESF) ventilation system maintains temperatures in the portions of the building housing ESF equipment within design limits for operation of equipment and for personnel access for inspection, maintenance, and testing, as required. The enclosures for ESF equipment are in the lower three levels of the auxiliary building and are ventilated by two separate ventilation systems.

The areas serviced by the ESF ventilation system include the following:

- containment spray pump enclosures
- RHR pump enclosures
- safety injection pump enclosures
- RHR heat exchanger enclosures
- containment spray heat exchanger enclosures
- reciprocating and centrifugal charging pump enclosures

For the purposes of license renewal, the ventilation subsystems servicing the following areas are reviewed with the ESF ventilation system:

- CCW pump rooms
- AFW pump rooms
- ESW pump rooms
- FP pump house

The safety intended functions of this system are to maintain a suitable operating environment for equipment located in the serviced areas and to remove iodine and particulates from ECCS leakage following an accident. The system also supports the Appendix R safe-shutdown analysis by providing cooling to the safe-shutdown equipment of the opposite unit. Therefore, the ESF ventilation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4 (a)(3).

Control Room Ventilation. The control room ventilation system maintains control room temperature and humidity and provides a fresh air supply to the control room during normal operation and accident conditions. One of two full-capacity air handling units supplies conditioned air to the control room envelope. The air conditioning system normally provides continuous pressurization of the control room envelope to prevent entry of dust and dirt. A separate air-handler with roughing filters, high efficiency particulate air filters, and charcoal adsorbers provides emergency filtration and pressurization.

The safety intended functions of the control room ventilation system are to maintain control room temperature during normal and accident conditions and to maintain dose to control room operators below the GDC-19 limits. In the event of a fire in the cable enclosure below the control room, the system prevents CO_2 intrusion into the control room. Therefore, the control room ventilation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Emergency Diesel Generator Ventilation. The EDG ventilation system maintains temperatures in the EDG rooms within acceptable limits for operation of the diesel generators and associated components, including the EDG control cabinets. The system also provides ventilation and removal of fuel oil vapors from the fuel oil day tank enclosure and the fuel oil pump room.

The EDG ventilation system performs the safety intended function of maintaining a suitable environment for the operation of the diesels. The system provides the additional FP function of removing fumes from the diesel generator fuel oil day tank room and the fuel oil pump room. Therefore, the EDG ventilation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Switchgear Ventilation. The switchgear ventilation system maintains temperature in various areas of the switchgear complex and N-train battery room within acceptable limits for operation of safety related equipment located in the rooms. Portions of the system provide a HELB barrier. The switchgear ventilation system also prevents accumulation of combustible concentrations of hydrogen gases inside the battery rooms.

The switchgear ventilation system performs the safety intended functions of maintaining room temperatures for safety related equipment and providing a HELB barrier. The system also performs a function related to FP. Therefore, the switchgear ventilation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Containment Ventilation. The containment ventilation system maintains temperatures in the various portions of the containment within acceptable limits for operation of equipment and for personnel access for inspection, maintenance, and testing, as required. The system can also purge the containment atmosphere to the environment via the plant vent and remove airborne contamination from containment before personnel entry.

The containment ventilation system consists of several essentially independent subsystems, including the following:

- containment purge supply and exhaust system
- instrumentation room purge supply and exhaust system
- containment pressure relief system
- upper compartment ventilation system
- lower compartment ventilation system
- CRDM ventilation system
- reactor cavity ventilation system
- pressurizer compartment ventilation system
- containment instrumentation room ventilation system
- hot sleeve ventilation system

The CEQ system, which is another independent containment ventilation system, is treated as a separate system (see Section 2.3.2.4 of this SER).

Of the independent subsystems included in the containment ventilation system, the only safety intended function is containment isolation, provided by certain system components.

In accordance with 10 CFR 54.4(a)(2), nonsafety related component types in the containment ventilation system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Housings, evaluated in Section 2.3.3.11 of this SER, represent the only nonsafety related component type that requires an AMR pursuant to 10 CFR 54.4(a)(2).

The containment ventilation system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2).

Security Diesel Generator Room Ventilation. The security diesel generator room ventilation maintains the security diesel generator room temperature. System components requiring an AMR include the intake and exhaust fans and associated ductwork. This ventilation system is considered part of the security system.

The security diesel provides power for emergency lighting for access to the N2 valves. The N2 valves are credited in the Appendix R safe-shutdown analysis and are considered safe-shutdown equipment. Therefore, the security diesel is required to support the safe-shutdown analysis, which brings the security diesel generator room ventilation within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(3).

Fuel Handling Area Exhaust. The fuel handling area exhaust system is a subsystem of the SFP system discussed in Section 2.3.3.1 of this SER. Two 30,000 cubic feet per minute exhaust fans associated with this system normally draw directly from the area. If the high radiation setpoint is reached, a radiation monitor in the SFP area trips the supply fans to the fuel handling area, opens the outlet dampers from the charcoal filters, and closes the dampers that bypass the charcoal filter bed. This is done to minimize the consequences of a fuel handling accident and minimize the release to the environs.

Therefore, the fuel handling area exhaust system performs a safety function and is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6 and CNP UFSAR Sections 5.5, 9.9, and 9.10 to determine whether there is reasonable assurance that the applicant identified the HVAC 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 staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with Section 2.3 of the SRP-LR.

In conducting its review, the staff examined the UFSAR to determine if the applicant omitted any safety-related system functions in accordance with the requirements of 10 CFR 54.4 as an intended function of the control room area ventilation system. The staff did not identify any omissions.

In addition, the staff evaluated system functions described in the LRA and UFSAR, in accordance with the requirements of 10 CFR 54.4, to verify that the applicant did not omit components having intended functions from the scope of license renewal. The staff also focused on components that the applicant did not identify as subject to an AMR to determine if any components were omitted.

To verify that the applicant identified the components of the HVAC 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 compared the referenced flow diagrams to the system drawings and descriptions in the UFSAR to ensure that the referenced flow diagrams are representative of the HVAC system. The staff then reviewed the referenced flow diagrams to verify that those portions of the HVAC that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in LRA Section 2.3.3.6. The staff also sought to verify that the applicant identified all HVAC 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 staff's review of LRA Section 2.3.3.6 did not identify areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff did not issue any RAIs to the applicant to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4 and the screening criteria of 10 CFR 54.21.

2.3.3.6.3 Conclusion

During its review of the information in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping results for HVAC components. The staff concludes that the applicant adequately identified the HVAC components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Fire Protection

2.3.3.7.1 Summary of Technical Information in the Application

In Section 2.3.3.7 of the LRA, the applicant described the FP system. The FP system rapidly detects and controls/suppresses fires while limiting their damage. The FP system comprises several FP subsystems and design features, including the following:

- fire detection system
- fire alarm and annunciation systems
- fire water supply distribution system
- fire water pumping systems
- water suppression systems
- gaseous suppression systems
- turbine bearing - dry chemical system
- manual fire fighting systems
- fire barriers - plant layout
- penetration seals
- fire doors
- fire dampers
- raceway fire barrier materials

- cable tray fire stops
- separation of engineered safety features actuation system and reactor protection system - Marinite board and Quelpyre tape
- west motor-driven auxiliary feedwater pump enclosure, Units 1 and 2
- roof smoke and heat vents
- floor drains

The water supply for the fire water tanks is the municipal water supply.

The Appendix R safe-shutdown analysis credits the FP system because it supplies cooling water to the security diesel, which powers lighting needed to achieve safe shutdown.

In accordance with 10 CFR 54.4(a)(2), nonsafety related portions of the system are subject to an AMR if their failure could prevent satisfactory accomplishment of a safety function. Components that require an AMR, based on the criteria of 10 CFR 54.4(a)(2), include liquid-filled FP components in the containment, auxiliary building, screenhouse, and the portion of the turbine building that contains the AFW pumps. Because these portions of the system are also within the scope of license renewal pursuant to 10 CFR 54.4(a)(3), no additional evaluation of FP system components is required for 10 CFR 54.4(a)(2).

The FP system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3).

In Table 2.3.3-7 of the LRA, the applicant identified the FP component types that are within the scope of license renewal and subject to an AMR, including bolting, expansion joint, filter housing, fittings, flange, flex hose, heat exchanger (bonnet), heat exchanger (shell), heat exchanger (tubes), heater housing, hydrant, level glass gauge, orifice, piping, pump casing, silencer, spray nozzles, strainer, strainer housing, tank, tubing, and valve.

2.3.3.7.2 Staff Evaluation

The NRC regulations in 10 CFR 54.21(a)(1) state that the applicant must identify and list those SSCs that are within the scope of this part, as delineated in 10 CFR 54.4, and that are subject to an AMR. The staff reviewed LRA Section 2.3.3.7, "Fire Protection," to determine whether there is reasonable assurance that the applicant appropriately identified the SSCs that serve FP intended functions as within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1), respectively. The staff conducted its review, described below, in accordance with Section 2.3 of the SRP-LR.

The staff sampled portions of the UFSAR to identify any additional FP system functions that meet the scoping requirements of 10 CFR 54.4 but that are not identified as an intended function in the LRA. The staff also reviewed the plant's Fire Protection Program Manual (FPPM). This manual directly references the plant's CLB documents and summarizes the Fire Protection Program and commitments pursuant to 10 CFR 50.48 using the guidelines of Appendix A to Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1. The staff reviewed portions of the FPPM to verify that the function of the FP components relied upon to satisfy the provisions of Appendix A to BTP APCSB 9.5-1 are included in the LRA and within the scope of license renewal as intended functions.

The staff then compared the FP SSCs identified in the flow diagrams to verify that the applicant highlighted the required components as within the evaluation boundaries on the flow diagram and did not exclude them from the scope of license renewal. As part of the evaluation, the staff also sampled portions of the same flow diagrams for the FP system to determine if any additional portions of the system piping or components located outside of the evaluation boundary should be identified as within the scope of license renewal.

In reviewing LRA Section 2.3.3.7, the staff identified areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated March 3, 2004, the staff issued an RAI concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's evaluation of the applicant's related responses to the RAIs.

RAI 2.3.3.7-1

In RAI 2.3.3.7-1(1), the staff requested information on LRA drawing 5152D concerning the note at location D-6 that provides details on a deluge valve found on LRA drawing 5152M. The LRA does not include this drawing, and the valve should be subject to an AMR. The applicant was asked to clarify whether the deluge valve is within the scope of license renewal or justify its exclusion.

In its response, dated September 21, 2004, the applicant stated that:

> The reactor coolant pump (RCP) suppression system deluge valves are not required by 10 CFR 50, Appendix R, or 10 CFR 50.48, and consequently do not serve a license renewal function. The nonessential service water (NESW) system, rather than the fire protection system, supplies water to these deluge valves. Because the water supply for these deluge valves does not originate from the in-scope fire protection system piping, which is depicted on license renewal drawing LRA-12-5152D, a passive failure of these valves would not prevent the fire protection system from supplying fire water to those portions of the system that are required by 10 CFR 50.48.
>
> Section III.O of Appendix R to 10 CFR 50 requires only a lubricating oil collection system for the protection of the RCP area. 10 CFR 50, Appendix R does not require a fire protection sprinkler system for the protection of this area. As approved in the SER for the CNP exemption to the 10 CFR 50, Appendix R, requirements applicable to the design of the CNP RCP motor lube oil collection system [..], the existing RCP lube oil collection system provides a level of safety equivalent to the technical requirements of 10 CFR 50, Appendix R, Section III.O.
>
> Therefore, the passive components of the deluge valves do not serve a license renewal intended function, and consequently, are not subject to aging management review.

The applicant states that the deluge valves serve no license renewal function because there is no interconnection to any required system; thus making the system not required. Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(1) acceptable.

In RAI 2.3.3.7-1(2), the staff asked for further analysis of the control circuit instrumentation at location H-5 on license renewal drawing LRA-12-5152D because it is connected to the FP system via a 1-inch water line and a normally open valve. The staff asked the applicant to clarify whether this item should be within the scope of license renewal or justify its exclusion.

In its response dated May 7, 2004, the applicant stated that the 1-inch line leading to SD-166 at location H5 on license renewal drawing LRA-12-5152D constitutes station drain 166. Valve 12-ZSO-60 is normally open to ensure that there is no water accumulation in the dry pipe header. Upon actuation of the fire suppression system in this area, solenoid-operated valve 12-ZSO-60 automatically closes to isolate the drain. The drain line downstream of valve ZSO-60 is not part of the required flowpath and does not affect the function of the FP system. Therefore, it is not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(2) acceptable because this drain pipe serves no emergency function.

In RAI 2.3.3.7-1(3), the staff requested clarification concerning the charcoal filters at locations C-6, E-8, J-8, and L-6 (shown in details B-3, E-3, J-3, and M-3) on drawing LRA-12-5152E, which have suppression components not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the charcoal filters at locations C6, E8, J8, and L6 on drawing LRA-12-5152E serve the containment pressure relief system (1-HV-CPR-1 and 2-HV-CPR-1) and the containment instrument room ventilation system (1-HV-CIPX-1 and 2-HV-CIPX-1). These HVAC filters do not have a license renewal intended function. The manual fire suppression capability provided by these fire water lines is not required for 10 CFR 50.48; thus, these components are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(3) acceptable because upon review of UFSAR, Section 5.5.3, the staff found that the ventilation systems involved are nonemergency-related systems.

In RAI 2.3.3.7-1(4), the staff requested further analysis of details D-6, D-9, K-3, K-6, and K-9 on LRA drawing 5152J that show what appear to be dry-pipe sprinkler systems with the air accumulator tanks (compressors) not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. Details K-3 and K-6 also show valves and supply piping, which are not highlighted, as portions of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the ZRC-series components at details D-6, D-9, K-3, K-6, and K-9 of drawing LRA-1-5152J are the retard chambers associated with the alarm check valves for several wet-pipe sprinklers. The retard chambers provide an alarm function and are active components that are not subject to an AMR. Components

1-ZFP-185 and 1-ZFP-358 at details K-6 and K-3 are alarm check valves for the wet-pipe sprinklers serving the north end of the turbine building and the abandoned diesel fire pump room in the screenhouse, which are areas requiring FP, based on the criteria 10 CFR 50.48. Therefore, these valves are subject to an AMR. The material and environment for the valves and downstream piping are the same as those for valves and piping that are already included in LRA Table 3.3.2-7. Component 1-TK-236 at detail K-9 is the air receiver for the dry-pipe sprinkler serving the main turbine lagging area. Loss of the air receiver would not prevent the function of the dry-pipe sprinkler; therefore, this component is not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(4) acceptable because the applicant identified the components which require an AMR. Retard chambers are considered active and nonvital alarm components to FP systems; therefore, they are not subject to an AMR.

In RAI 2.3.3.7-1(5), the staff requested further analysis of details C-6, H-6, L-6, D-9, and L-9 on LRA drawing 5152K, which show what appear to be dry-pipe sprinkler systems with the air accumulator tanks (compressors) not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. Detail L-6 also shows valves and supply piping to the diesel fire pump room, which are not highlighted, as portions of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the ZRC-series components at details C-6, H-6, L-6, D-9, and L-9 of drawing LRA-2-5152K are the retard chambers associated with the alarm check valves for the wet-pipe sprinklers. The retard chambers provide an alarm function and are active components; therefore, they are not subject to an AMR. Components 2-ZFP-185 and 2-ZFP-358 at details H-6 and L-6 are alarm check valves for the wet-pipe sprinklers serving the south end of the turbine building and the abandoned diesel fire pump room in the screenhouse, which are areas requiring FP pursuant to 10 CFR 50.48. Therefore, these valves are subject to an AMR. The material and environment for the valves and downstream piping are the same as those for valves and piping that are already included in LRA Table 3.3.2-7. Component 2-TK-237 at detail D-9 is the air receiver for the dry-pipe sprinkler serving the main turbine lagging area. Loss of the air receiver would not prevent the function of the dry-pipe sprinkler; therefore, this component is not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(5) acceptable because the applicant identified the components which require an AMR. Retard chambers are considered active and nonvital alarm components to FP systems; therefore, they are not subject to an AMR.

In RAI 2.3.3.7-1(6), the staff requested further analysis of detail G-4 on LRA drawing 5152L, which shows what appears to be a dry-pipe sprinkler system with the air accumulator tank (compressors) not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. Details G-7 and G-9 show the license renewal boundary established at a normally open valve. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the ZRC-series components at detail G-4 of drawing LRA-12-5152L are the retard chambers associated with the alarm check valves for two wet-pipe sprinklers. The retard chambers provide an alarm function and are active components; therefore, they are not subject to an AMR. Components 12-ZFP-360, 12-ZFP-361, and 12-ZFP-169 at details G-7 and G-9 are the alarm check valves for areas requiring FP, based on the requirements of 10 CFR 50.48. Therefore, these valves are subject to an AMR. The material and environment for the valves and downstream piping are the same as those for valves and piping that are already included in LRA Table 3.3.2-7. The other alarm check valves at detail G-9 are for areas that do not require FP pursuant to 10 CFR 50.48; therefore, they are not subject to an AMR. In the event of a failure of any components in this normally pressurized water suppression FP header, station personnel will take appropriate actions to assure that system intended functions are maintained.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(6) acceptable because the applicant identified the components that require an AMR. Retard chambers are considered active and nonvital alarm components to FP systems; therefore, they are not subject to an AMR.

In RAI 2.3.3.7-1(7), the staff requested further evaluation of detail G-3 on LRA drawing 5152N, which shows what appears to be a dry-pipe sprinkler system with the air accumulator tank (compressors) and drain not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. In addition, detail E-7 shows a valve and sprinkler supply for the auxiliary building drumming room and radiation waste material handling building not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the components at detail G-3 of drawing LRA-12-5152N are the air compressor and receiver for a dry-pipe sprinkler. Loss of the air receiver would not prevent the function of a dry-pipe sprinkler; therefore, this component is not subject to an AMR. Component 12-ZFP-264 at detail E-7 is the alarm check valve for the auxiliary building drumming room, the radioactive waste material handling building, and the Unit 2 personnel passageway. The auxiliary building drumming room/personnel passageway is an area requiring FP based on the requirements of 10 CFR 50.48; therefore, this valve is subject to an AMR. The material and environment for the valves and downstream piping are the same as those for valves and piping that are already included in LRA Table 3.3.2-7. The radioactive waste material handling building does not require FP pursuant to 10 CFR 50.48; thus, the associated water sprinkler piping is not subject to an AMR. In the event of a failure of any components in this normally pressurized water suppression FP system header, station personnel will take appropriate actions to assure system intended functions are maintained.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(7) acceptable, because some components identified are not required for the FP system and the areas identified are outside of the scope of license renewal. The radioactive waste material handling building does not require FP on the basis of 10 CFR 50.48; thus the associated water sprinkler piping is not subject to an AMR.

In RAI 2.3.3.7-1(8), the staff requested further explanation of detail L-3 on LRA drawing 5152R, which shows a valve and sprinkler supply for the containment access building not highlighted as portions of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether these items should be within the scope of license renewal or justify their exclusion.

In its response dated May 7, 2004, the applicant stated that the components at detail L-3 of drawing LRA-12-5152R are the FP (water) supply components for the containment access building. This building houses the offices for the radiation protection department and serves as the primary entry/exit point for the radiologically restricted area. It is not connected to seismic structures, houses no safety-related equipment, and does not require FP pursuant to 10 CFR 50.48. Therefore, these FP components are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(8) acceptable, because the protected area is outside the scope of license renewal. This office building does not require FP on the basis of 10 CFR 50.48; therefore, its related FP components are not subject to an AMR.

In RAI 2.3.3.7-1(9), the staff asked why locations C-2 and D-6 on LRA drawing 5152S show the Lake Charter Township water supply not highlighted as a portion of the flow diagram within the scope of license renewal and subject to an AMR. The staff requested the applicant to clarify whether this item should be within the scope of license renewal or to justify its exclusion.

In its response dated May 7, 2004, the applicant stated that the Lake Charter Township water supply piping connections shown on drawing LRA-12-5152S are not credited for response to a fire pursuant to 10 CFR 50.48. The contained volume in the fire water storage tanks is sufficient to extinguish the 10 CFR 50.48 design-basis fire without makeup from offsite sources.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(9) acceptable, because the lake supply is supplemental and not required for FP.

In RAI 2.3.3.7-1(10), the staff requested further analysis of location H-9 on LRA drawing 5152T, which shows the fire pump test header not highlighted as a portion of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether this item should be within the scope of license renewal or to justify its exclusion.

In its response dated May 7, 2004, the applicant stated that the fire pump test header and associated components shown on drawing LRA-12-5152T are normally isolated from the fire water header and do not provide a 10 CFR 50.48 FP function; thus, they are not subject to AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(10) acceptable, because the test connection is isolated from the water header.

In RAI 2.3.3.7-1(11), the staff asked why locations F-6 and G-6 on LRA drawing 5153 show the suppression system supply from normally open valves to the computer rooms not highlighted as a portion of the flow diagram within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether this item should be within the scope of license renewal or to justify its exclusion, and to verify that the procedures include operator actions to close these valves when needed.

In its response dated May 7, 2004, the applicant stated that the original FP carbon dioxide suppression supply components for the computer rooms have been abandoned in place and are no longer functional. As shown on drawing LRA-12-5153 at locations F-6 and G-6, blanking flanges are installed downstream of valves 1-FCO-171 and 2-FCO-172.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(11) acceptable, because abandoned systems are not within the scope of license renewal.

In RAI 2.3.3.7-1(12), the staff requested the applicant to provide the basis for the battery room at location E-8 on LRA drawing 5153G not appearing to have CO_2 protection. The staff asked the applicant to verify whether some form of protection has been provided in this area or justify the exclusion of fire suppression.

In its response dated May 7, 2004, the applicant stated that automatic fire suppression is not provided for the Unit 2 AB battery room (fire zone 46D). This zone is equipped throughout with early warning ionization detection, which will alert the control room operators of a fire condition, allowing fire brigade personnel to be dispatched to the zone. Portable fire extinguishers and water hose reels provide manual fire suppression.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1(12) acceptable because it identified the FP features of the room.

RAI 2.3.3.7-2

In RAI 2.3.3.7-2(1), the staff inquired about the fire pump installation, which the applicant indicated is in accordance with National Fire Protection Association (NFPA) 20, "Standard for the Installation of Stationary Pumps for Fire Protection." However, the LRA drawings submitted do not include a pressure maintenance pump. The staff asked the applicant to verify the presence of a pressure maintenance pump and include it on the drawings. The applicant should also state whether it is within the scope of license renewal and subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the FP pegging pump (12-PP-146) shown at location G5 on drawing LRA-12-5152T is the system pressure maintenance pump. The pump is within the scope of license renewal and subject to an AMR. Tables 2.3.3-7 and 3.3.2-7 of the LRA include it in the component type "pump casing."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-2(1) acceptable because it identified an adequate pressure maintenance pump that is within the scope of license renewal.

In RAI 2.3.3.7-2(2), the staff requested further discussion on the manually operated foam suppression systems. The LRA drawings submitted do not show any foam systems. The staff asked the applicant to verify the location of any foam suppression systems and show them on the drawings. The applicant should also clarify whether they are within the scope of license renewal and subject to an AMR.

In its response dated May 7, 2004, the applicant stated that manually operated foam suppression racks are provided in various locations in the turbine building and screenhouse. Five-gallon cans of foam are monitored and sampled in accordance with plant procedures.

They are considered consumables, analogous to fire extinguishers, and as such are not shown on LRA drawings and do not require an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-2(2) acceptable because it identified, located, and discussed manually operated foam suppression. These systems do not require an AMR.

In RAI 2.3.3.7-2(3), the staff requested further discussion of any halon systems. The LRA drawings submitted do not show any halon systems. The staff asked the applicant to verify the location of any halon fire suppression systems and show them on the drawings. The applicant should also clarify whether they are within the scope of license renewal and subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the halon tanks (1-TK-274A, B, C, E, F, and G and 2-TK-275A, B, C, E, F, and G) are shown at locations J6 to M6 and J9 to M9 on drawing LRA-12-5154A. This drawing shows the distribution components and piping to the control room cable vaults, with some continued at locations G2 and G6 on drawing LRA-12-5153L. These components are within the scope of license renewal and subject to an AMR. The component type "tank," listed in LRA Tables 2.3.3-7 and 3.3.2-7 includes the tanks and internal cylinder valves exposed to an internal halon environment. The component types "flex hose," "piping," "spray nozzles," and "valve" listed in these tables include other components and piping exposed to an internal air environment.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-2(3) acceptable because it identified, located, and discussed all halon systems and identified the AMR requirements.

2.3.3.7.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the components of the FP system. Therefore, the staff concludes that the applicant has adequately identified the FP system 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 FP system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Emergency Diesel Generators

2.3.3.8.1 Summary of Technical Information in the Application

In Section 2.3.3.8 of the LRA, the applicant described the EDG system. The EDG system provides a reliable, automatic onsite power source with sufficient capacity to operate ESF and protection system loads to ensure the safe shutdown of the reactor and mitigate the consequences of a design-basis accident in the event offsite power is lost. Each diesel engine is equipped with its own auxiliaries, including the following:

- starting and control air
- fuel oil
- lubricating oil

- cooling water
- intake and exhaust system
- voltage regulator
- controls

The safety intended function of the EDG system is to provide power to ESF and protection system loads. The Appendix R safe-shutdown analysis credits the EDG as a potential source of alternating current power for recovery from an SBO. Therefore, the EDG system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

In Table 2.3.3-8 of the LRA, the applicant identified the EDG component types that are within the scope of license renewal and subject to an AMR, including bolting, compressor, dryer, expansion joint, filter housing, fittings, flex hose, heat exchanger (shell), heat exchanger (tubes), heater housing, level glass gauge, manifold (piping), orifice, piping, pneumatic cylinder, pump casing, sight flow indicator, silencer, strainer, tank, thermowell, trap, tubing, and valve.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8 and CNP UFSAR Section 8.4 to determine whether there is reasonable assurance that the applicant identified the EDG system 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 staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.8 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.8-1

The applicant showed several components as subject to an AMR on the EDG license renewal drawings but did not list them in LRA Table 2.3.3.8 for EDG components subject to an AMR. These components are passive and long-lived and serve a pressure boundary function. The staff asked the applicant to justify the exclusion of the following components from Table 2.3.3.8:

a. intake manifold coolers with cooling coils, air receivers, air distributors, and turbocharger housings

b. 3/4" fuel drips

In its response dated May 7, 2004, the applicant stated the following about RAI 2.3.3.8-1:

a. As shown on license renewal drawings, Intake manifold aftercoolers, are subject to an AMR and are included in component types "Heat exchanger (shell)" and "Heat exchanger (tubes)" listed in LRA Table 2.3.3-8. Starting air receivers are subject to an AMR and are included in component type "Tank" listed in LRA Table 2.3.3-8. Air distributor housings are subject to an AMR, but were omitted from LRA Tables 2.3.3-8 and 3.3.2-8. The carbon steel housing and copper alloy air distributor ring have the intended function of pressure boundary and are exposed to air internally and externally. The aging effect requiring management for internal carbon steel surfaces exposed to air is loss of material, which will be managed by the Preventive Maintenance Program. The aging effect requiring management for the external carbon steel surfaces exposed to air is loss of material, which will be managed by the System Walkdown Program. There are no aging effects requiring management for copper alloy exposed to air.

   Turbocharger housings are subject to aging management review and are included in component type "Compressor" listed in LRA Table 2.3.3-8.

b. Drip lines are not subject to aging management review. Refer to the response to RAI 2.3.3.8-3

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-1 acceptable, because it clarifies that (1) intake manifold aftercoolers are included in the heat exchanger component type, (2) starting air receivers are included in the tank component type, (3) air distributors are subject to an AMR but were omitted from Table 2.3.3-8, (4) turbocharge housings are included in the compressor component type, and (5) fuel drip lines are not subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.3.8-1 are resolved.

RAI 2.3.3.8-2

Table 2.3.3-8 of the LRA lists heater housing as a component type subject to an AMR. However, the license renewal drawings show the lubricating oil filter electric heater housings as excluded from an AMR. The staff asked the applicant to clarify whether these heaters penetrate the pressure boundary of the system bypass oil filters and whether the parts of these heaters that support the intended function of maintaining the pressure boundary are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(2) and 10 CFR 54.21(a)(1).

In its response, dated May 7, 2004, the applicant stated that electric heaters penetrate the pressure boundary of the by-pass oil filters and are bolted to the bypass lube oil filter housings. These heater housings are considered part of the by-pass lube oil filter housings; the filter housings are evaluated with the component type, "filter housing" in LRA Tables 2.3.3-8 and 3.3.2-8.

The portion of the electric heaters that form the by-pass lube oil filter pressure boundary should have been highlighted on drawings LRA-1-5151A, LRA-2-5151A, and LRA-1-5151C, as was done on drawing LRA-2-5151C. The parts of these heaters that support the intended function of maintaining the pressure boundary of the filter housings are subject to an AMR and are included with the component type "filter housing" in LRA Tables 2.3.3-8 and 3.3.2-8. The component type "heater housing" in LRA Table 2.3.3-8 refers to the lube oil heaters (QT-11 6-AB/CD), shown on drawings LRA-1-5151A, LRA-1-5151C, LRA-2-5151A, and LRA-2-5151C at location F9.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-2 acceptable because the components in question are adequately represented under respective component types and are listed in Table 2.3.3-8. Additionally, the portions of the electric heaters that form a pressure boundary have been evaluated for an AMR. Therefore, the staff's concerns described in RAI 2.3.3.8-2 are resolved.

RAI 2.3.3.8-3

The license renewal drawings show 3/4" contaminated drip lines to the engine room sump as subject to an AMR. These lines continue on P&IDs 5180 and 12-5180, which are not included in the license renewal drawing index. Therefore, the staff could not determine if the applicant identified all the contaminated drip line components that meet the criteria of 10 CFR 54.4(a)(2) as subject to an AMR and listed them as component types in LRA Table 2.3.3-8. To make this determination, the staff asked the applicant to provide these drawings or text information to identify the EDG fuel oil drip line components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response, dated May 7, 2004, the applicant stated that the drip lines to the engine room sump shown on drawings LRA-1-5151A, LRA-2-5151A, LRA-1-5151C, and LRA-2-5151C were highlighted in error. The contaminated drip lines are open-ended lines used for draining fuel oil leakage to the engine room sump during engine operation. These drip lines do not have an intended function that is in accordance with 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3). The supports for these drain lines that are required to provide structural support (including seismic II/I) are within scope of license renewal. The supports for these drain lines are included in the commodity type "piping supports" in LRA Tables 2.4-5 and 3.5.2-5, on pages 2.4-21 and 3.5-60, respectively.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-3 acceptable because the applicant clarified that it highlighted the drip lines in error. The staff evaluated the functions of these lines and finds the response to RAI 2.3.3.8-3 adequate. Therefore, the staff's concerns described in RAI 2.3.3.8-3 are resolved.

RAI 2.3.3.8-4

License renewal drawings LRA-1-5151A, LRA-2-5151A, LRA-1-5151C, and LRA-2-5151C show lubricating oil coolers. License renewal drawings LRA-1-5151B, LRA-2-5151B, LRA-1-5151D, and LRA-2-5151D show jacket water coolers as subject to an AMR. Table 2.3.3-8 does not list heat exchanger channels and tubesheets, although the table does list heat exchanger shell with an intended function of pressure boundary and heat exchanger tubes with an intended function *of heat transfer as components subject to an AMR. The staff asked the applicant to explain the* exclusion of the heat exchanger channels and tubesheets from Table 2.3.3-8.

In its response dated May 7, 2004, the applicant stated that the channels and tubesheets of the EDG lubricating oil coolers QT-110-AB/CD and jacket water coolers QT-131-AB/CD are subject to an AMR, but the applicant inadvertently omitted them from LRA Table 3.3.2-8. The tubesheets of the lubricating oil and jacket water coolers are made of carbon steel and are exposed to fresh raw water on one side and either lubricating oil or treated jacket water on the other. The cooler channels are cast iron and are exposed to fresh raw water internally and air externally. The applicant included the AMR results for these components in the response to RAI 2.3.3.8-4.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-4 acceptable because the applicant clarified that it omitted the heat exchanger channels and tubesheets from Table 3.3.2-8 in error. The applicant evaluated these components in the LRA. Therefore, the staff's concerns described in RAI 2.3.3.8-4 are resolved.

RAI 2.3.3.8-5

For those systems, structures, and components within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff was unable to decide whether the applicant has considered all the SCC's within the scope of license renewal to satisfy this requirement.

LRA Section 2.1.2.1.1 states that the identification of components subject to an AMR began with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff is unable to verify whether the applicant identified all the components that perform an intended function because in its LRA, the applicant did not identify the components within the system evaluation boundary. The staff needs to verify this information to effectively review the LRA using the guidance in the SRP-LR.

The applicant was asked to confirm that the system components marked on license renewal drawings for the EDG system depict all the components that perform an intended function. If not, the applicant was asked to provide a list of those components that perform an intended function but are not marked on license renewal drawings or provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings include all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are within the scope of license renewal and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators.

Instead of depicting process flow information, the diesel fuel oil equipment location plan sketches included on license renewal drawings depict equipment layout. This information duplicates that shown elsewhere on the license renewal drawings for the EDGs; consequently, the applicant did not highlight these equipment location plans.

The license renewal drawings do not depict any short-lived components that perform a 10 CFR 54.4 intended function. No EDG system components are within scope for the 10 CFR 54.4(a)(2) criteria.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-5 acceptable because the applicant adequately identified and described the components. Therefore, the staff's concerns described in RAI 2.3.3.8-5 are resolved.

RAI 2.3.3.8-6

The failure of nonsafety related components that could affect the ability of their associated EDG to perform its intended function should be within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The EDGs have exhaust silencers that appear to support the EDG's intended functions. These are long-lived, passive components. However, the applicant did not identify the exhaust silencers on the license renewal drawings as within the scope of license renewal. The staff asked the applicant to justify the exclusion of the exhaust silencers from the scope of license renewal and from being subject to an AMR.

In its responses dated August 19, 2004 and October 18, 2004 and in a telephone conference dated September 1, 2004, the applicant stated that the exhaust silencers are included within the scope of license renewal and are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-6 acceptable because the EDG exhaust silencers have been adequately identified as within the scope of license renewal and are subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.8-6 is resolved. Commitment #37 in Appendix A of this SER cites the AMP that will manage the aging effects for the EDG exhaust silencers.

RAI 2.3.3.8-7

The failure of nonsafety related components that could affect the ability of their associated EDG from performing its intended function should be within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The EDGs have centrifugal exhausters that appear to support intended functions. These are long-lived, passive components. However, the applicant did not identify the centrifugal exhausters on the license renewal drawings as within scope of license renewal. The staff asked the applicant to justify the exclusion of the centrifugal exhausters from the scope of license renewal and from an AMR.

In its response dated July 26, 2004, and by telephone conference dated September 1, 2004, the applicant stated that the EDG centrifugal exhausters are nonsafety-related components in the crankcase breather subsystem. This EDG subsystem maintains a slight vacuum in the crankcase to remove vapors and minimize oil leakage. This function is not required for diesel engine operation, and a failure of these components would not render the EDG inoperable.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-7 acceptable because the applicant gave adequate explanation about the function of the centrifugal exhausters and how their failure would not affect the EDG's intended function. Therefore, the staff's concern described in RAI 2.3.3.8-7 is resolved.

2.3.3.8.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the EDG system. Therefore, the staff concludes that the applicant adequately identified the EDG SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the EDG system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Security

2.3.3.9.1 Summary of Technical Information in the Application

In Section 2.3.3.9 of the LRA, the applicant described the security system. The security system protects against radiological sabotage pursuant to 10 CFR Part 73 and provides adequate lighting for access to the N2 valves to perform safe-shutdown functions (Section IIIJ.of Appendix R to 10 CFR Part 50). The security system consists of the security diesel generator, lights, alarms, doors, intrusion detection devices, metal detectors, explosive detectors, gates, and communication equipment.

The security diesel provides power for emergency lighting for access to the N2 valves. The Appendix R safe-shutdown analysis credits the N2 valves as safe-shutdown equipment. Therefore, the security diesel is required to support the safe-shutdown analysis, and the system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(3).

Section 2.3.3.6 of the LRA evaluates the security diesel generator room ventilation with the HVAC systems.

In Table 2.3.3-9 of the LRA, the applicant identified the security component types that are within the scope of license renewal and subject to an AMR, including bolting, compressor casing, expansion joint, filter housing, fittings, flange, flex hose, heat exchanger (shell), heat exchanger (tubes), heater housing, piping, pump casing, silencer, strainer, strainer housing, tank, thermowell, tubing, and valve.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 to determine whether there is reasonable assurance that the applicant identified the security system 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 staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of the LRA Section 2.3.3.9 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.9-1

License renewal drawing LRA-12-5150B shows a vent as subject to an AMR. However, LRA Table 2.3.3-9 does not list the component group "vent." The staff asked the applicant to clarify whether vents are considered part of the component group "piping" in Table 2.3.3-9. If not, the staff asked the applicant to justify the exclusion of this component from an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response dated May 7, 2004, the applicant stated that the fuel oil tank vent piping shown on drawing LRA-12-5150B is subject to an AMR and is included in the component type "piping" listed in LRA Table 2.3.3-9.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-1 acceptable because it clarifies that the component type "piping" in LRA Table 2.3.3-9 includes vents. Therefore, the staff's concern in RAI 2.3.3.9-1 is resolved.

RAI 2.3.3.9-2

The staff asked the applicant to clarify whether the components of the security diesel generator shown on license renewal drawing LRA-12-5150B are treated as a complex assembly. If the security diesel generator is treated as a complex assembly, the applicant must identify the boundaries of the security diesel generator so that the staff may determine whether its subcomponents are subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(3) and 10 CFR 54.21(a)(1).

In its response dated May 7, 2004, the applicant stated that the security diesel generator is considered a complex assembly for the CNP LRA. The mechanical subsystems of the security diesel generator are subject to an AMR. The applicant identified the security diesel generator components subject to an AMR in LRA Table 2.3.3-9. The diesel generator engine itself is an active component.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-2 acceptable because it clarifies that the security diesel engine is the boundary of the complex mechanism and that the subsystems are subject to an AMR. Therefore, the staff's concern in RAI 2.3.3.9-2 is resolved.

RAI 2.3.3.9-3

License renewal drawing LRA-12-5150B shows two jacket water coolers within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify whether LRA Table 2.3.3-9 lists these jacket water coolers as part of the component type "heat exchanger" and subject to an AMR. If not, the staff asked the applicant to justify the exclusion of these components from Table 2.3.3-9.

In its response dated May 7, 2004, the applicant stated that the jacket water coolers 12-HE-68-I and 12-HE-68-2 are subject to an AMR and are included in the component types "heat exchanger (shell)" and "heat exchanger (tubes)" listed in LRA Table 2.3.3-9.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-3 acceptable because it clarifies that the component types "heat exchanger (shell)" and "heat exchanger (tubes)" in LRA Table 2.3.3-9 include the jacket water coolers. Therefore, the staff's concern in RAI 2.3.3.9-3 is resolved.

RAI 2.3.3.9-4

For those SSCs within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff could not determine if the applicant considered all the SSCs within the scope of license renewal to satisfy this requirement.

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function, because in its LRA the applicant did not identify the components within the system evaluation boundary. The staff must verify this information to effectively review the LRA using the guidance of the SRP-LR.

The staff asked the applicant to confirm that the system components marked on license renewal drawings for the security diesel system depict all the components that perform an intended function. If not, the staff asked the applicant to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or to provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are within scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, which includes items such as instrumentation, motors, and valve operators.

The applicant did not depict any short-lived components that perform a 10 CFR 54.4 intended function on license renewal drawings. No security diesel system components are within scope for the 10 CFR 54.4(a)(2) criteria.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-4 acceptable, because the security system components that are highlighted on the license renewal drawings have been adequately described. Therefore, the staff's concerns described in RAI 2.3.3.9-4 are resolved.

2.3.3.9.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the security system. Therefore, the staff concludes that the applicant adequately identified the security system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the security system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Post-Accident Containment Hydrogen Monitoring

2.3.3.10.1 Summary of Technical Information in the Application

In Section 2.3.3.10 of the LRA, the applicant described the postaccident containment hydrogen monitoring system (PACHMS). The PACHMS monitors the containment atmosphere for hydrogen concentrations following a LOCA to assist in determining the need for initiation of the hydrogen recombiners. The PACHMS comprises two sampling-analyzing control trains. Each train has a hydrogen analyzer panel and a remote control panel. The PACHMS can take samples from nine locations within the containment. After analysis, the sample is returned to the containment.

The primary safety intended functions of the system include sampling and analyzing containment hydrogen following an accident and providing containment isolation. Therefore, the PACHMS is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

In Table 2.3.3-10 of the LRA, the applicant identified the PACHMS component types that are within the scope of license renewal and subject to an AMR, including analyzer body, bolting, filter, fittings, flex hose, heat exchanger, moisture separator, orifice, piping, pump casing, and valve.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 and UFSAR Section 7.8 using the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting the review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff found that the applicant included those portions of the PACHMS that meet the scoping requirements of 10 CFR 54.4 within the scope of license renewal, and it identified them as such in LRA Section 2.3.3.10. The staff also found that LRA Table 2.3.3-10 includes the PACHMS components that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.10.3 Conclusion

During its review of information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the PACHMS. Therefore, the staff concludes that the applicant adequately identified the PACHMS SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the PACHMS SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)

2.3.3.11.1 Summary of Technical Information in the Application

In Section 2.3.3.11 of the LRA, the applicant described the miscellaneous systems within scope for 10 CFR 54.4(a)(2). The applicant's scoping effort took place before the development of industry guidance on scoping based on the criteria of 10 CFR 54.4(a)(2). Consequently, the applicant undertook a separate scoping effort to incorporate existing industry guidance (specifically, spatial interaction). This section discusses the result of this additional scoping effort. The applicant identified systems within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2) using the method described in Section 2.1.1.2 of the LRA. These systems may be categorized into two groups:

(1) systems that are within the scope of license renewal for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3), as well as 10 CFR 54.4(a)(2), whose AMR results are presented in sections other than Section 3.3.2.1.11 of the LRA

(2) systems that are within the scope of license renewal based solely on the criteria of 10 CFR 54.4(a)(2), whose AMR results are presented in Section 3.3.2.1.11 of the LRA

As discussed in the system descriptions, some of these systems in the second group have components that are included in the evaluation of other systems, such as containment isolation.

Group 1 Systems. For systems in Group 1, the environment and materials are the same for the portion of the system affected by 10 CFR 54.4(a)(2) as for those portions evaluated under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). Therefore, the AMR results discussed for these systems in Section 3 of the LRA also apply to the portion of the system affected by 10 CFR 54.4(a)(2). Section 3.3.2.1.11 does not include components from these systems.

The following are Group 1 systems:

- blowdown
- component cooling water
- chemical and volume control
- essential service water
- feedwater
- main steam
- reactor coolant
- *fire protection*

Group 2 Systems. Group 2 systems are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2), described below. Section 3.3.2.1.11 of the LRA presents the AMR results for those portions of the system affected by 10 CFR 54.4(a)(2). Table 2.3.3-11 of the LRA lists the components in these systems that were evaluated based on the requirements of 10 CFR 54.4(a)(2). In some cases, components in these systems are included in other system evaluations. As appropriate, these are noted to provide a complete system description.

Auxiliary Steam. The auxiliary steam (AS) system provides reduced-pressure steam to various plant subsystems to support plant operation. The AS system supplies certain subsystems, including plant heating, steam jet air ejectors, turbine steam seals, and FP. The AS system is in the form of a ring header and is cross-connected between the CNP units. The plant heating boiler supplies steam to the AS system when both units are out of service.

Chemical Feed. The chemical feed system injects chemicals for pH and dissolved oxygen control into the condensate system and into the steam generators. The chemical feed system includes the condensate and feedwater chemical tanks, pumps, and piping. Section 2.3.4.1 of the LRA evaluates the safety related isolation valves and piping in the chemical feed lines to the main feedwater headers within the main feedwater system.

Containment. Containment includes mechanical components providing containment drainage. Containment drainage collects and transports liquid from floor, equipment, and ice condenser equipment drains to the waste disposal system via drain pots or sumps. Certain components used for containment drainage are subject to an AMR, based on the criteria of 10 CFR 54.4(a)(2), and are not covered by any other AMR. Structural portions of containment are evaluated in LRA Section 2.4.1. Bulk structural commodities are evaluated in LRA Section 2.4.5.

Demineralized Water. The demineralized water system produces high-purity, degassified water for makeup to the RCS and condensate-feedwater systems and to other plant services. Lake water from the nonessential service water (NESW) system is filtered, chlorinated, and held in a retention tank to effect complete sterilization. An alternate source of supply is the Lake Charter Township public water system.

The demineralized water system includes containment penetrations that supply demineralized water to the refueling cavity and containment pipe tunnel during outages. Under accident conditions, these penetrations provide containment isolation. Section 2.3.2.2 of the LRA evaluates containment isolation components.

Process Drains. The process drains system collects drainage from various process systems. The system collects drainage from the waste evaporator and north and south boric acid evaporators, pumping it to the miscellaneous drain tank. It also collects drainage from various secondary plant SSCs and directs it either to the main condenser for reuse or to the turbine room sump for discharge.

Ice Condenser. The ice condenser system provides a flowpath and sufficient ice to absorb thermal energy from a LOCA or a MSLB to limit containment pressure rise to less than design pressure immediately following an accident. The ice condenser system assists in iodine removal from the containment atmosphere and provides an inventory source for the containment recirculation sump to support sump recirculation level, pH, and boron requirements. The ice condenser system refrigeration components maintain the ice bed temperature within analyzed limits and replenish the ice beds during outages. The ice condenser system includes the following:

- system structural steel
- ice baskets
- pressure-activated doors
- various components that cool the ice bed

The ice baskets that support the ice blowdown flowpath pressure-activated doors and associated structural components provide the safety intended functions of the system (postaccident containment pressure and temperature control, iodine removal, and sump inventory source). Sections 2.4.1 and 2.4.5 of the LRA evaluate these components along with structural components. Safety related portions of the system refrigeration components also provide containment isolation when required. Section 2.3.2.2 of the LRA evaluates containment isolation components.

Lake Charter Township Water. The Lake Charter Township water system supplies water for the makeup pretreatment and filtration plant and the dedicated FP water supply tanks. The Lake Charter Township water system also supplies cooling water for the NESW pump seals and potable water for the plant site.

Nonessential Service Water. The NESW system provides cooling water to various plant heat loads that have no safety functions. The NESW system supplies heat loads, including the turbine oil coolers, air compressors, upper and lower containment ventilation units, and RCP motor air coolers. The NESW pumps take suction from either CNP, Unit 1 or Unit 2, circulating water (CW) intake tunnels or discharge tunnels and discharge into either CNP, Unit 1 or Unit 2, CW discharge tunnels.

The NESW lines to containment are isolated during accident conditions. Section 2.3.2.2 of the LRA evaluates the containment isolation components.

Nuclear Sampling. The purpose of the nuclear sampling (NS) system is to process and condition representative samples from designated plant fluid systems for in-line analyzers and grab samples for laboratory analysis. Samples are drawn from the following sources:

- pressurizer steam space
- pressurizer liquid space

- two reactor coolant hot legs (loops 1 and 3)
- each of the four accumulators
- two RHR lines
- CVCS letdown line at the demineralizer inlet and outlet headers
- volume control tank gas space
- each of the four steam generator blowdown lines

The safety intended functions of the NS system are to provide containment isolation and to maintain the pressure boundary of the safety related system being sampled, including the RCPB. Maintaining the RCPB also supports the Appendix R safe-shutdown analysis and the SBO event. Therefore, this system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3), as well as 10 CFR 54.4(a)(2).

This section evaluates the NS system components that meet the criteria of 10 CFR 54.4(a)(2). The remaining components of the NS system subject to an AMR are evaluated with a number of different systems. Portions of the NS system that have the safety related function of maintaining the system pressure boundary are evaluated in the respective system review as follows:

- RCS in Section 2.3.1 of the LRA
- ECCS in Section 2.3.2.3 of the LRA
- blowdown in Section 2.3.4.4 of the LRA
- main steam in Section 2.3.4.2 of the LRA

Containment penetration isolation components for sample lines from various systems in containment are evaluated either with the sampled system or as part of the consolidated containment isolation evaluation in Section 2.3.2.2 of the LRA.

Post-Accident Sampling. The postaccident sampling system (PASS) provides representative samples for laboratory analysis following a LOCA. The system is common to CNP, Units 1 and 2. Samples are provided from RCS loop 1 and 3 hot legs, the pressurizer steam space, the containment sump, and the RHR system. Provisions have been made for drawing gas samples in each unit from the containment air space. These samples can be analyzed by in-line equipment or collected and transported to the laboratory in a shielded container.

Section 2.3.2.2 of the LRA evaluates components in the PASS that provide containment isolation.

Primary Water. The primary water system supplies water to miscellaneous services within the auxiliary building and the containment, primarily for reactor coolant makeup. Major components include the primary water storage tanks and primary water pumps.

The primary water line to containment is isolated in accident conditions. Section 2.3.2.2 of the LRA evaluates containment isolation components.

Radioactive Waste Disposal. The radioactive waste disposal system collects and processes liquid, gas, and solid radioactive wastes. The gaseous waste subsystem collects and processes potentially radioactive gases discharged from various components and systems for recycling, storage, and discharge at concentrations below the regulatory limits. The liquid waste subsystem collects, processes, and stores radioactive liquid waste from various plant systems and drains in the auxiliary building and containment. The solid waste subsystem stores resin for a short decay time before subsequent packaging for shipment and provides for compression and drumming of solid wastes.

Section 2.3.2.2 of the LRA evaluates components in the radioactive waste disposal system that provide containment isolation.

Station Drainage. The station drainage system collects spillage, drains, and overflows in the auxiliary building, containment, and turbine building. Collected fluids are routed to various sumps for disposal. The system includes station drainage piping, floor drains, and sump pumps.

Section 2.3.2.2 of the LRA evaluates containment isolation components associated with this system.

Spent Fuel Pool Cooling. SFP cooling removes, from the SFP, the heat generated by stored spent fuel elements. The components of the CNP SFP cooling provide no intended functions. The spent fuel pit provides the maintenance of pool inventory, which assures cooling, as discussed in Section 2.3.3.1 of the LRA. The two units share the SFP. The design incorporates two separate cooling trains sharing a common return line to the SFP. Piping is arranged so that failure of any pipe does not drain the SFP below the top of the stored fuel elements.

The clarity and purity of the SFP water is maintained by passing the cooling flow through a filter and a demineralizer. Skimmers are provided to prevent dust and debris from accumulating on the surface of the water. The refueling water purification pump and filter can be used separately or in conjunction with the SFP demineralizer to regain refueling water clarity after a crud burst in either unit. SFP cooling is also used to maintain water quality in the RWSTs of both units.

Screen Wash System. The screen wash system supplies water from Lake Michigan (the ultimate heat sink) to the CW system and the ESW system for CNP, Units 1 and 2, and returns it to the lake. Traveling water screens are provided in the intake structure to remove debris and fish. The screen wash system includes the following components:

- intake crib
- intake piping
- discharge piping
- forebay
- traveling screens (*i.e.*, baskets, drives, and trash collection)
- screen wash pumps
- associated valves and sluice gates

The intended function of this system is to provide a flowpath to and from the ultimate heat sink to the ESW system via the intake and discharge tunnels. Failure of this function, performed by nonsafety related equipment, could affect a safety function. For license renewal, Section 2.4.3 of the LRA evaluates this equipment with the screenhouse structure. Therefore, this section does not evaluate any components in the screen wash system. The screen wash system does not have the potential for spatial interaction with safety related equipment.

Radiation Monitoring. The radiation monitoring system (RMS) detects, computes, and records radiation levels. The RMS comprises a collection of small, independent systems located at selected points in and around the plant. These systems are composed of area monitors, process monitors, and environmental monitors.

The RMS has a containment isolation function. Section 2.3.2.2 of the LRA evaluates containment isolation components associated with this system.

Ventilation Systems—Auxiliary Building Ventilation, Miscellaneous Ventilation, and Containment Ventilation. As described in UFSAR Section 9.9, the auxiliary building ventilation system (VA) encompasses four different ventilation subsystems in the auxiliary building. The organization of these subsystems in this application is consistent with their safety functions. Section 2.3.3.6 of the LRA describes the ESF ventilation and fuel handling area exhaust (fuel handling ventilation). The two remaining auxiliary building ventilation subsystems, as described in UFSAR Section 9.9, are the general ventilation systems and the general supply system. Other than the potential for spatial interactions with safety related equipment, no auxiliary building ventilation functions meet the criteria for inclusion within the scope of license renewal.

The miscellaneous ventilation system includes ventilation subsystems in various locations throughout the plant site. The ventilation subsystems maintain appropriate environmental conditions for the location served. Other than the potential for spatial interactions with safety related equipment, no miscellaneous ventilation functions meet the criteria for inclusion within the scope of license renewal.

Section 2.3.3.6 of the LRA describes the containment ventilation system, and it has components evaluated with the ventilation systems. As discussed below, certain fan housings are included with the AMR results in Section 3.3.2.1.11 of the LRA.

In these three ventilation systems, the majority of passive, nonsafety related components contain only air and therefore do not require an AMR. However, components that contain liquid require an AMR. Some of these components (cooling coils) are contained in packaged ventilation units that isolate these components from leakage or spray onto safety related components. Housings for these ventilation units are subject to an AMR.

Components not contained in housings are part of chilled water systems that supply cooling water to ventilation units in the auxiliary building ventilation and miscellaneous ventilation systems. These components are in the auxiliary building and consist of the following:

- bolting
- condensers
- strainers
- pumps
- valves
- tanks
- glass level gauges
- tubing and piping

In Table 2.3.3-11 of the LRA, the applicant identified the miscellaneous systems within scope for 10 CFR 54.4(a)(2) component types that are within the scope of license renewal and subject to an AMR, including bolting, condenser shell, evaporator housing, filter housing, flex hose, heat exchanger (shell), heater coil, heater housing, level glass gauge, manifold (piping), orifice, piping, pump casing, strainer housing, tank, thermowell, trap, tubing, valve, and ventilation unit housing.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 and CNP UFSAR Sections 5.3, 5.5, 9.4, 9.6, 9.8.3, 9.9, 10.6, 10.9, 10.10, 11.1, 11.1.2.1.4, and 11.3 to determine whether there is reasonable assurance that the applicant identified the nonsafety related mechanical components within the auxiliary steam, chemical feed, containment drainage, demineralized water, process drains, ice condenser, Lake Charter Township water, nonessential service water, nuclear sampling, post-accident sampling, radioactive waste disposal, station drainage, SFP cooling, screen wash, and radiation monitoring and ventilation systems that are within the scope of license renewal and subject to an AMR in accordance with the criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.21(a)(1), respectively. The staff conducted its review in accordance with SRP-LR, Section 2.3 guidance.

In its review, the staff selected system functions described in the LRA and UFSAR that were set forth in 10 CFR 54.4(a) to verify that components having intended functions were not omitted from the scope of license renewal. The staff then reviewed the components within the scope of license renewal in accordance with 10 CFR 54.4(a) to verify that passive and long-lived components were not omitted from being subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.11 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.3.11-1

Section 2.3.3.11 of the LRA describes 17 systems within the scope of license renewal and subject to an AMR based on the criteria of 10 CFR 54.4(a)(2). However, the applicant did not explain how failure of these systems or components within these systems may affect the safety-related components/systems intended functions. The staff asked the applicant to provide additional information which describes how failure of these nonsafety-related systems results in the failure of a safety-related system or component to perform its intended function.

In its response dated May 7, 2004, the applicant stated that the criteria for nonsafety-related SSCs whose failure could prevent the accomplishment of safety functions are either functional or spatial. In a functional failure, the nonsafety-related SSC fails to perform its normal function thereby impacting a safety function. In a spatial failure, the loss of structural or mechanical integrity of a nonsafety-related SSC in physical proximity to a safety-related component impacts a safety function of the safety-related component.

The applicant provided two tables that identify by system and building location the nonsafety-related component types meeting the criteria of 10 CFR 54.4(a)(2). The tables identify how the failure of the component type potentially affects a safety related SSC.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.11-1 acceptable because it adequately describes the types of component failures and their effects on components meeting the criteria of 10 CFR 54.4(a)(2). Therefore, the staff's concern in RAI 2.3.3.11-1 is resolved.

RAI 2.3.3.11-2

Table 2.3.3-11 of the LRA identifies component types and intended functions as a group for 17 systems. The staff could not identify which component types and intended functions in the table correlate to which of the 17 systems described in LRA Section 2.3.3.11. The applicant did not provide license renewal drawings for these systems, and the UFSAR does not provide sufficient descriptive information. Therefore, the staff could not conclude whether the applicant identified the mechanical system components for these systems that are within the scope of license renewal and subject to an AMR. To make this determination, the staff asked the applicant to provide drawings or text information which identify the components by system that are subject to an AMR because they meet the intended function of 10 CFR 54.4(a)(2) and 10 CFR 54.21(a)(1). If LRA Table 2.3.3-11 excludes any of these components, the staff asked the applicant to revise the table.

In responses dated May 7, 2004 and September 2, 2004, as well as discussions during an August 24, 2004 teleconference, the applicant stated that nonsafety-related components containing liquid or steam located in the containment building, auxiliary building, screenhouse, and the portion of the turbine building that contains the AFW pumps are considered to be subject to an AMR unless no safety related equipment is in the area. The applicant further described the area containing these components as a plant space that is on the same floor (elevation) in a building with no barrier walls between the nonsafety related fluid-filled system and the safety related components. At CNP, areas are identified with room numbers. Structural walls form the boundary of a room on the same elevation of a major building and separate safety related components from a spray or a leak from a nonsafety related component. These walls are within the scope of license renewal and subject to an AMR. The applicant further explained that if no safety related components are installed in the same area as the nonsafety related fluid-filled components, then these nonsafety related components do not meet 10 CFR 54.4(a)(2) and are not included within the scope of license renewal. The applicant discussed examples of components that are excluded from the scope of license renewal.

Based on its evaluation, the staff finds the applicant's responses to RAI 2.3.3.11-2 acceptable because the staff did not find any omissions of nonsafety related components subject to an AMR. In addition, the staff concludes that the applicant defined the population of components within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff considers its concern described in RAI 2.3.3.11-2 resolved.

RAI 2.3.3.11-3

The LRA implies that the SFP cooling system does not perform an intended function as defined in 10 CFR 54.4. In addition, license renewal drawings show portions of the CCW system piping between the license renewal boundary flags to and from the spent fuel pit heat exchangers as excluded from an AMR. However, UFSAR Section 9.4.1 states, "Any spent fuel pool off-loading scenario, including a full core off-load of two units, which meets the 82 °C (180 °F) peak bulk pool temperature with one train of cooling and 5.8 hours to boil criteria is acceptable."

From this statement, it is not clear that water in the SFP can maintain sufficient shielding and prevent the release of radioactive gases, given the 82 °C (180 °F) peak bulk pool temperature and 5.8 hour time to boil criteria without activation of at least one cooling train. The staff asked the applicant to justify why at least one train of SFP cooling is not within the scope of license renewal in accordance with 10 CFR 54.4(a).

In its response dated May 7, 2004, the applicant stated that the SER for CNP License Amendments 260 and 243 provides the basis for the UFSAR statement cited above. The UFSAR statement evaluated conditions related to the approval of a change to shorter starts of core offload dependent on maximum ultimate heat sink temperatures during two periods in a year.

The SER concludes the following:

> For planned refueling conditions with both cooling trains in service, SFP water temperature will stay below 142.3 °F, which is below the long term SFP design temperature of 150 °F. In the event that one SFP cooling train fails, the remaining SFP cooling train will maintain SFP temperature below the SFP design temperature of 180 °F.
>
> In the unlikely event of a sustained loss of both SFP cooling trains, the available makeup capacity exceeds the maximum potential rate of evaporative losses, and these makeup sources can be aligned within the time available prior to the onset of boiling. Therefore, the staff concludes that the reliability and capacity of SFP cooling and makeup systems are adequate to deal with the increased heat load, resulting from the proposed reduction in decay time.

The reference to the 82 °C (180 °F) peak bulk pool temperature in the cited UFSAR statement reflects the evaluation of the loss of one train of SFP cooling. The reference to the 5.8-hour time to boil criteria reflects the evaluation for loss of all SFP cooling.

In its response to RAI 2.3.3.1-1 dated September 2, 2004, the applicant credits the FP system to provide adequate makeup to the SFP in the event of loss of fuel pool cooling capability. The FP system is in the scope of license renewal. Its capability is in excess of capacity required to maintain pool water level at the maximum potential rate of evaporative losses. However, the FP system alone does not provide the diversity of makeup water sources specified within the licensing basis of the facility. This issue has been addressed in Section 2.3.3.1.

2.3.3.11.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the miscellaneous systems. Therefore, the staff concludes that the applicant has adequately identified the miscellaneous system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the miscellaneous system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Miscellaneous Systems

2.3.3.12.1 Summary of Technical Information in the Application

In Section 2.3.3.12 of the LRA, the applicant described the miscellaneous systems. This section discusses various systems that are within the scope of license renewal, but the components subject to an AMR have been included in the mechanical system reviews or the structural reviews. The systems' descriptions include discussions of the components subject to an AMR and references to the sections containing the component evaluations.

Material/Equipment Handling. The material/equipment handling (MATL) system safely moves material and equipment as required to support operations and maintenance activities. The system consists of plant cranes (including associated components such as trolleys and bridges) that lift, control, and transport loads in the auxiliary building, turbine building, containment, screenhouse, service building, sewage treatment building, radioactive waste handling building, and other miscellaneous buildings.

Major equipment in the MATL system includes the following:

- east auxiliary building crane
- west auxiliary building crane
- containment polar cranes
- main turbine building crane
- auxiliary turbine building cranes
- ice condenser cranes

The normal functions of the MATL system do not require that the system be included within the scope of license renewal. However, the system is included because of the potential for spatial interactions with safety related equipment, which is in accordance with 10 CFR 54.4(a)(2). Section 2.4 of the LRA evaluates the cranes as structural components.

Nuclear Fuels. The nuclear fuel (NF) system includes the fuel racks, NF assemblies, and the rod cluster control assemblies (including the wet annular burnable absorber) that together provide and enable control of the nuclear heat source. The fuel and control components provide a safe and controllable source of power to heat the reactor coolant water. The fuel racks store new and used fuel that is not in service in the reactor core.

As their primary safety intended function, the fuel and control components provide a barrier for fission products, a coolable configuration for the NF, and control and shutdown capability for the core. The ability to safely shut down the reactor core also supports the Appendix R safe-shutdown analysis and the SBO event. Therefore, the NF system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3). These components are not subject to an AMR because they are periodically replaced.

As its primary safety intended function, the fuel racks prevent criticality of the stored fuel. Section 2.4.2 of the LRA evaluates the fuel racks as structural components in the auxiliary building.

Refueling. The refueling system performs core alterations and other fuel movements, including movements within the SFP. The system includes the following:

- fuel transfer system
- upending devices
- refueling cavity manipulator cranes
- new and spent fuel handling crane
- new fuel elevator
- a variety of handling tools

Normal functions of the refueling system do not require inclusion of the system in the scope of license renewal. However, the system is included because of the potential for spatial interactions with safety related equipment, which is in accordance with 10 CFR 54.4(a)(2). The refueling cavity manipulator cranes and the new and spent fuel handling crane require an AMR. Section 2.4 of the LRA evaluates the cranes as structural components in the structures that house them.

Residual Heat Removal. For license renewal, LRA Section 2.3.2.3 evaluates the RHR system as part of the ECCS. The containment spray evaluation in LRA Section 2.3.2.1 includes portions of the spray header that are supplied by the RHR system.

Reactor Vessel Level Instrumentation. The RVLIS indicates the relative vessel water level or the relative void content of fluid in the vessel during postaccident conditions. This level indication assists personnel in recognizing conditions that may lead to damage of the vessel or the core. Sensors measuring the differential pressure between the vessel head and bottom and between the head and the hot legs provide the basis for level and void fraction indication.

The safety intended function of the mechanical portions of the system is to maintain the RCPB, which is in accordance with 10 CFR 54.4(a)(1). Section 2.3.1 of the LRA includes this system in the review of the RCS.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 (regarding nuclear fuels, RHR, and reactor vessel level indication) and CNP UFSAR Chapter 3 and Sections 9.7 and 4.2.11 to determine whether the applicant identified the miscellaneous systems components within the scope of license renewal and subject to AMR. The staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance described in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR, in accordance with the requirements of 10 CFR 54.4(a), to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that it did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

On the basis of its review, the staff found that the applicant identified those portions of the miscellaneous systems that meet the scoping requirements of 10 CFR 54.4(a) and included them within the scope of license renewal in LRA Section 2.3.3.12. The applicant also included the miscellaneous systems components that are subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.12.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the miscellaneous systems. Therefore, the staff concludes that the applicant adequately identified the miscellaneous systems SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the miscellaneous systems SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

In Section 2.3.4 of the LRA, the applicant identified the SCs of the steam and power conversion systems that are subject to an AMR for license renewal.

The applicant described the following components of the steam and power conversion systems:

- main feedwater
- main steam
- auxiliary feedwater
- steam generator blowdown
- main turbine

The applicant determined the steam and power conversion systems SSCs that are within the scope of license renewal as described in the following sections.

2.3.4.1 Main Feedwater

2.3.4.1.1 Summary of Technical Information in the Application

In Section 2.3.4.1 of the LRA, the applicant described the main feedwater system. The main feedwater system supplies feedwater to the steam generators at appropriate temperature, pressure, and flow rates under all steady-state and transient load conditions. The main feedwater system uses turbine-driven feedwater pumps to supply water from the condensate system to the steam generators. The main feedwater system includes high-pressure feedwater heaters to improve plant thermal efficiency by preheating the feedwater.

The main feedwater flowpath from the main feedwater check valves to the steam generators is safety related. This portion of the system provides an extension of the containment liner and provides a flowpath for the AFW to the steam generators. In addition to these safety intended functions, the system also provides ESF actuation system feedwater isolation and feedwater regulating valve closure when required.

The mechanical function required of the main feedwater system during an SBO event is to maintain the secondary system pressure boundary from the main feedwater check valves to the steam generators. The mechanical functions required of the main feedwater system during an Appendix R safe-shutdown event are to maintain the same portion of the secondary system pressure boundary and to support AFW addition to the steam generators.

The main feedwater system is also included in the scope of license renewal because of the potential for spatial interactions with safety related equipment. The main feedwater system nonsafety related components requiring an AMR pursuant to 10 CFR 54.4(a)(2) are in the auxiliary building.

Therefore, the main feedwater system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.3.4-1 of the LRA, the applicant identified the main feedwater component types that are within the scope of license renewal and subject to an AMR, including bolting, piping, and valve.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 and CNP UFSAR Section 10.5.1 to determine whether there is reasonable assurance that the applicant identified the main feedwater system 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 staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.4.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.4.1-1

LRA Section 2.3.4.1 states that the FW system is in the scope of license renewal based on the potential for spatial interactions with safety-related equipment. License renewal drawings only show the safety-related portion of the FW system which is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1). The remainder of the FW system is continued on additional drawings that are not included in the LRA. Therefore, the staff is unable to determine whether those FW system components that meet 10 CFR 54.4(a)(2) criteria are identified as component types subject to an AMR in LRA Table 2.3.4-1. The staff asked that the applicant provide drawings or text information that identifies the FW system components within the scope of license renewal because they meet the criteria of 10 CFR 54.4(a)(2) as described. If any of these components which are passive and long-lived are not included as a component type in LRA Table 2.3.4-1, the applicant was asked to revise this table.

In its response dated May 7, 2004, the applicant stated that nonsafety-related component types in the feedwater system that require an AMR under 10 CFR 54.4(a)(2) are located in the auxiliary building and consist of the component types of bolting, orifices, thermowells, valves, manifolds, tubing, and piping. AMPs for the environment and material combinations identified in LRA Table 3.4.2-1 will manage aging for the component types listed above. In its responses to RAI 2.3.3.11-2 dated May 20, 2004, and September 2, 2004, the applicant discussed the scoping and screening of components meeting the criteria of 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-1 acceptable because it adequately addressed the questions concerning the scoping and screening of components meeting the criteria of 10 CFR 54.4(a)(2) and identified the location of the nonsafety related portions of the main feedwater system that meet the criteria of 10 CFR 54.4(a)(2). Therefore, the staff's concerns described in RAI 2.3.4.1-1 are resolved.

RAI 2.3.4.1-2

For those SSCs within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff could not determine if the applicant considered all the SSCs within the scope of license renewal to satisfy this requirement.

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function because it did not identify the components within the system evaluation boundary in its LRA. The staff must verify this information to effectively review the LRA using the SRP-LR.

The staff asked the applicant to confirm that the system components marked on license renewal drawings for the main feedwater system depict all the components that perform an intended function. If not, the applicant was asked to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of feedwater regulating valves and the feedwater isolation valves that have an active function of feedwater isolation upon receipt of an ESF actuation system signal. The ESF actuation system functions of the feedwater isolation and feedwater regulating valve closure rely on the active function of the motor-operated feedwater isolation valves or the pneumatically operated feedwater regulating valves. Both sets of valves prevent the supply of feedwater to the steam generators and do not require pressure boundary integrity of this portion of the system. If pressure boundary is lost in this portion of the system, interruption of feedwater flow to the steam generator would occur. Therefore, these feedwater valves and this portion of the system do not require an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-2 acceptable. The applicant adequately described the process for identifying system components on license renewal drawings that are subject to an AMR. The applicant described as necessary the components that meet the requirements of 10 CFR 54.4(a) but are not shown on the license renewal drawings and discussed the alteration of the system evaluation boundaries. Therefore, the staff confirmed that the applicant evaluated all the components with intended functions for an AMR, including those components at license renewal system boundaries and interfaces with other systems. The applicant identified as necessary those components within the system evaluation boundary for a license renewal system that are not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.4.1-2 is resolved.

RAI 2.3.4.1-3

Section 2.1.2.1.2 of the LRA states that the applicant created the license renewal drawings by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an AMR. Components that are within the scope of license renewal based solely on the criteria of 10 CFR 54.4(a)(2) are not generally indicated on the drawings but are described in LRA Section 2.3 and listed in LRA Table 3.3.2-11.

Pursuant to 10 CFR 54.21(a)(1), the applicant must identify and list those SCs subject to an AMR. The staff's position is that the applicant had not satisfied this requirement because the components of the main feedwater system meeting the criteria of 10 CFR 54.4(a)(2) are neither identified on drawings nor listed. The applicant included the component types instead of individually listed components. Therefore, the staff asked the applicant to confirm that the main feedwater system components marked on license renewal drawings depict all the components within the main feedwater system that meet the criteria of 10 CFR 54.4(a)(2). If not, the applicant was asked to provide a list of components not marked on license renewal drawings or provide revised drawings as needed to include the additional components.

In its responses dated May 20, 2004, and September 2, 2004, the applicant confirmed that the LRA tables group the components meeting the criteria for 10 CFR 54.4(a)(2) as component types instead of as individual components.

The applicant's 10 CFR 54.4(a)(2) identification process, as described in the response to RAI 2.3.3.11-2, designates nonsafety-related systems and components with the potential for spray or leakage that could prevent safety-related systems and components from performing their required safety functions. Conservatively, the applicant determined all nonsafety-related components containing liquid or steam located in the auxiliary building and screenhouse to be subject to an AMR unless no safety-related equipment is in the area.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-3 acceptable because it provided an adequate explanation in its responses to RAI 2.3.3.11-2 about the components in the auxiliary building and screenhouse that are subject to an AMR according to the criteria of 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.1-3 is resolved.

2.3.4.1.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the main feedwater system. Therefore, the staff concludes that the applicant adequately identified the main feedwater system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the main feedwater system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Main Steam

2.3.4.2.1 Summary of Technical Information in the Application

In Section 2.3.4.2 of the LRA, the applicant described the main steam system. The main steam system delivers steam from the steam generators to the turbine and to other equipment or systems requiring main steam, including the following:

- turbine driver of an auxiliary feedwater pump
- main feed pump turbines
- reheaters
- turbine bypass system (steam dump)
- auxiliary steam system
- turbine steam seals (Unit 2 only)

The main steam flowpath from the steam generators to the main steam isolation valves is safety related. This portion of the main steam system provides the primary safety intended functions, including removing heat from the RCS via the main steam safety valves to prevent RCS overpressurization. This portion of the system also provides an extension of the containment liner and a flowpath to the main steam safety valves, AFW pump turbine, and steam generator PORVs.

With the main steam isolation valves closed, the steam generator PORVs can be used to provide a controlled cooldown. In addition to these safety intended functions, the system also provides containment isolation of the steam sampling lines when required. The controlled cooldown function with the steam generator PORVs also supports the Appendix R safe-shutdown and SBO events.

The main steam system is also included in the scope of license renewal because of the potential for spatial interactions with safety related equipment. The nonsafety related components in the main steam system that require an AMR under 10 CFR 54.4(a)(2) are in the auxiliary building and the turbine building in the auxiliary feedwater pump rooms.

Therefore, the main steam system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.3.4-2 of the LRA, the applicant identified the main steam component types that are within the scope of license renewal and subject to an AMR, including bolting, manifold (piping), orifice, piping, tubing, and valve.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and CNP UFSAR Section 10.2 to determine whether there is reasonable assurance that the applicant identified the main steam system 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 staff used the evaluation methodology described in Section 2.3 of this SER. The staff conducted its review in accordance with the guidance in Section 2.3 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of the LRA Section 2.3.4.2 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.4.2-1

Section 2.3.4.2 of the LRA states the following:

> The main steam system is also included in the scope of license renewal due to the potential for spatial interactions with safety-related equipment. The non-safety-related components in the main steam system that require aging management review for 10 CFR 54.4(a)(2) are in the auxiliary building and the turbine building in the auxiliary feedwater pump rooms.

Section 2.1.2.1.2 of the LRA states that components within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2) are not indicated on the drawings but are described in LRA Section 2.3 and listed in LRA Table 3.3.2-11.

License renewal drawings LRA-1-5105D, LRA-2-5105D, LRA-1-5141A, and LRA-2-5141A show the safety-related portion of the main steam system only from the steam generators to the main steam isolation valves. This portion of the system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1). License renewal drawing LRA-1-5105 shows the nonsafety related portion of the system downstream of the isolation valves up to the high-pressure turbine. However, the drawing does not highlight any components belonging to the main steam system. Additionally, LRA Table 3.3.2-11 lists component types under the general heading of "Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)" rather than associating them with specific systems. As a result, by using this table and the license renewal drawings provided, the staff could not verify that the applicant properly identified all main steam system components within the scope of license renewal and subject to an AMR.

Therefore, the staff asked the applicant to clarify whether all the nonsafety-related components of the main steam system are within the scope of license renewal, because of a potential spatial interaction with safety-related equipment, and subject to an AMR in accordance with 10 CFR 54.4(a)(2) and 10 CFR 54.21(a)(1). If not, the applicant was asked to identify which components are within scope and subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the nonsafety-related component types in the main steam system that require an AMR pursuant to 10 CFR 54.4(a)(2) are located in the auxiliary building and inside the AFW pump rooms in the turbine building. They consist of bolting, tanks, strainers, traps, valves, tubing, and piping. As described in LRA Section 2.3.3.11, the main steam system is a Group 1 system. For systems in Group 1, the material and environments are the same in the portion of the system meeting the criteria of 10 CFR 54.4(a)(2) as for those portions meeting the criteria of 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). AMPs for the environment and material combinations identified in LRA Table 3.4.2-2 will manage aging for all the component types listed above.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-1 acceptable because the applicant identified the location of the nonsafety related portions of the main steam system that meet the criteria of 10 CFR 54.4(a)(2) and provided the component types subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.4.2-1 are resolved.

RAI 2.3.4.2-2

License renewal drawings LRA-1-5105D and LRA-2-5105D show the four main steam isolation valves and their actuators. Section 10.2.2 of the UFSAR describes the design of these actuators. The drawings show the actuator cylindrical housings as within the scope of license renewal and subject to an AMR. However, LRA Table 2.3.4-2 does not specifically list these housings as a component type subject to an AMR. These housings are passive, long-lived components and meet the requirements of 10 CFR 54.21(a)(1) for an AMR. Therefore, the staff asked the applicant to clarify whether one of component types listed in LRA Table 2.3.4-2 includes these housings. If not, the staff requested the applicant to justify the exclusion of these housings from an AMR.

In its response dated May 7, 2004, the applicant stated that the steam cylinders for the steam generator stop valves MRV-210, 220, 230, and 240 form part of the main steam pressure boundary and are an integral part of the valve bodies. The steam cylinders and other portions of the valve body are highlighted on license renewal drawings. They are included in the AMR for the main steam system and in the component type "valve."

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-2 acceptable because the applicant has identified that the steam cylinders for the valves are included in the AMR for main steam since they are steam-filled pressure boundaries of the main steam system. Therefore, the staff's concerns described in RAI 2.3.4.2-2 are resolved.

RAI 2.3.4.2-3

For those SSCs within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff could not decide whether the applicant considered all the SSCs within the scope of license renewal to satisfy this requirement.

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function because it did not identify the components within the system evaluation boundary in the LRA. The staff must verify this information to effectively review the LRA using the SRP-LR.

Therefore, the staff asked the applicant to confirm that the system components marked on the license renewal drawings for the main steam system depict all the components that perform an intended function. If not, the applicant was asked to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are in scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators.

Marking up the license renewal drawings to show components that are in scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2) would be of minimal value, if any, since such components are included in scope if they are installed in the area of safety related SSCs. Proximity to safety related SSCs cannot be determined from functional flow diagrams.

The main steam system license renewal drawings do not depict any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-3 acceptable because the applicant adequately identified and described the components. Therefore, the staff's concerns described in RAI 2.3.4.2-3 are resolved.

RAI 2.3.4.2-4

Section 2.1.2.1.2 of the LRA states that the applicant created the license renewal drawings by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an AMR. Components that are within the scope of license renewal based solely on the criteria of 10 CFR 54.4(a)(2) are not generally indicated on the drawings but are described in LRA Section 2.3 and listed in LRA Table 3.3.2-11.

Pursuant to 10 CFR 54.21(a)(1), the applicant must identify and list those SCs subject to an AMR. The staff's position is that the applicant did not satisfy this requirement because the components of the main steam system meeting the criteria of 10 CFR 54.4(a)(2) are neither identified on drawings nor listed. The applicant included these as component types instead of individually listed components. Therefore, the staff asked the applicant to confirm that the main steam system components marked on license renewal drawings depict all the components within the main steam system that meet the criteria of 10 CFR 54.4(a)(2). If not, the applicant was asked to provide a list of these components that are not marked on license renewal drawings or provided revised drawings as needed to include the additional components.

In responses dated May 20, 2004 and September 2, 2004, the applicant stated that the LRA tables group the components meeting the criteria of 10 CFR 54.4(a)(2) as component types instead of as individual components.

The applicant's 10 CFR 54.4(a)(2) identification process, as described in response to RAI 2.3.3.11-2, designates nonsafety-related systems and components with the potential for spray or leakage that could prevent safety-related systems and components from performing their required safety function. Conservatively, the applicant determined all nonsafety-related components containing liquid or steam located in the auxiliary building and screenhouse to be subject to an AMR unless no safety-related equipment is in the area.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-4 acceptable, because it provided an adequate explanation in its responses to RAI 2.3.3.11-2 about the components in the auxiliary building and screenhouse that are subject to an AMR under the criteria of 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.2-4 is resolved.

2.3.4.2.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the main steam system. Therefore, the staff concludes that the applicant adequately identified the main steam system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the main steam system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Auxiliary Feedwater

2.3.4.3.1 Summary of Technical Information in the Application

In Section 2.3.4.3 of the LRA, the applicant described the AFW system. The AFW system provides feedwater to the steam generators when the main feedwater supply is not available. The system is the safety related source of feedwater for cooling as required during DBEs. The system also provides feedwater as required for the SBO and FP regulated events.

Installed in each unit is one turbine-driven AFW pump, which feeds all four steam generators, and two motor-driven AFW pumps, each of which feeds two steam generators. Train orientation is maintained throughout the AFW system, including the AFW pumps, all associated valves, instrumentation, and controls. The CST normally provides the water for the AFW pumps. The ESW system serves as an emergency water source. The motor-driven AFW pumps can supply the corresponding sets of steam generators in the opposite unit through manual cross-tie supply valves.

Therefore, the AFW system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

In Table 2.3.4-3 of the LRA, the applicant identified the AFW component types that are within the scope of license renewal and subject to an AMR, including bolting, fittings, governor housing, heat exchanger (shell), heat exchanger (tubes), manifold (piping), orifice, piping, pump casing, sight glass, sight glass housing, strainer housing, tank, tubing, turbine casing, and valve.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3 and CNP UFSAR Section 10.5.2 to determine whether there is reasonable assurance that the applicant identified the AFW system 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 staff conducted its review in accordance with the SRP-LR, Section 2.3 guidance.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.4.3 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.4.3-1

Section 2.3.4.3 of the LRA states, "The floating head seal and associated support posts are included in the AMR because the failure of the seal could cause flow blockage." License renewal drawings LRA-1-5106A and LRA-2-5106A show the CSTs for Units 1 and 2 as subject to an AMR. However, both of these drawings show the floating head seal to be excluded from an AMR, and LRA Table 2.3.4-3 does not list it as a component type subject to an AMR. Therefore, the staff asked the applicant to explain why the floating head seal on the CST, although stated earlier to be subject to an AMR, is not highlighted on the license renewal drawings nor listed in Table 2.3.4-3 as a component type subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the floating head seal and associated support posts are included in the AMR because the failure of the seal could cause flow blockage. Since the seal does not have a unique component number in the database, LRA Table 2.3.4-3 includes it in the component type "tank." As listed in LRA Table 3.4.2-3 under the component type "tank," elastomer tank components may experience change in material properties or cracking. It is an administrative oversight that license renewal drawings LRA-1-5106A and LRA-2-5106A do not highlight the seals to show that they are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.3-1 acceptable because the applicant identified where the LRA tables identify the condensate tank floating head seal and described it as subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.4.3-1 are resolved.

RAI 2.3.4.3-2

License renewal drawings LRA-1-5106A and LRA-2-5106A show strainers upstream of the three AFW pumps. Table 2.3.4-3 of the LRA includes strainer housings as a component type subject to an AMR; however, this table does not list strainer internals. Failure of the strainer internals could prevent the strainer from performing its intended function, or possibly cause a flow blockage. Therefore, the staff asked the applicant to clarify whether these strainer internals are long-lived and passive. If so, the applicant should justify why Table 2.3.4-3 does not include the strainer internals as subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response dated May 7, 2004, the applicant stated that strainers upstream of the AFW pumps have a component intended function of filtration. They are long-lived, passive, and subject to an AMR. The applicant inadvertently omitted the strainer internals from LRA Tables 2.3.4-3 and 3.4.2-3. The stainless steel strainer internals are submerged in treated water in AFW pump suction piping, which is the same environment as the stainless steel AFW suction piping. The AERM is a loss of material, which is managed by the Primary and Secondary Water Chemistry Control Program. Table 3.4.2-3 of the LRA should include the entry, "Component Type—Strainer internals, Intended Function—Filtration, Material—Stainless steel, Environment—Treated water (internal), Aging Effect Requiring Management—Loss of material, Aging Management Programs—Water Chemistry Control."

Based on its review, the staff finds the applicant's response to RAI 2.3.4.3-2 acceptable because the AFW pump strainer internals are now included in the appropriate LRA tables and are subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.4.3-2 are resolved.

RAI 2.3.4.3-3

License renewal drawing LRA-1-5106A shows turbine oil cooler HE-70 and governor oil cooler HE-71 as within scope and subject to an AMR. Table 2.3.4-3 of the LRA lists the heat exchanger subcomponents "shell" and "tubes" as separate component types subject to an AMR. However, the LRA table does not list the other subcomponents of the lubricating oil coolers, such as tubesheets and channel heads. Furthermore, license renewal drawing LRA-1-5106A does not identify the cooling water system used to cool the lubricating oil. Therefore, the staff asked the applicant to identify the coolers' cooling water system and justify why it does not consider other heat exchanger internal subcomponents such as tubesheets and channel heads to be subject to an AMR, or to revise Table 2.3.4-3 to include these items.

In its response dated May 7, 2004, the applicant stated that the turbine oil cooler and governor oil cooler use water from the AFW system itself for cooling. The turbine-driven AFW pump discharge is diverted to flow through the turbine oil cooler and governor oil cooler. Subcomponents of the lubricating oil coolers, such as tubesheets and channel heads, are subject to an AMR but are not listed in LRA Table 2.3.4-3. The AMPs that apply to the shell and tubes also apply to the subcomponents included in the component types "heat exchanger (shell)" and "heat exchanger (tubes)" in LRA Table 2.3.4-3.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.3-3 acceptable because it clarifies the cooling medium for the coolers. In addition, the LRA table represents the component types that describe the cooler subcomponents. Therefore, the staff's concerns described in RAI 2.3.4.3-3 are resolved.

RAI 2.3.4.3-4

For those SSCs within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff could not determine whether the applicant considered all the SSCs within the scope of license renewal to satisfy this requirement.

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function because it did not identify the components within the system evaluation boundary in the LRA. The staff must verify this information to effectively review the LRA using the SRP-LR.

Therefore, the staff asked the applicant to confirm that the system components marked on license renewal drawings for the AFW system depict all the components that perform an intended function. If not, the applicant was asked to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or to provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings indicate all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are in scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators.

The AFW system license renewal drawings do not depict any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.3-4 acceptable, because it adequately identifies and describes the components. Therefore, the staff's concerns described in RAI 2.3.4.3-4 are resolved.

2.3.4.3.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the AFW system. Therefore, the staff concludes that the applicant adequately identified the AFW system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the AFW system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Steam Generator Blowdown

2.3.4.4.1 Summary of Technical Information in the Application

In Section 2.3.4.4 of the LRA, the applicant described the steam generator blowdown (SGBD) system. The SGBD system maintains the proper water chemistry within the steam generators on the secondary side. The system has a safety intended function of blowdown isolation for AFW flow conservation and automatic isolation capability. The portion of the SGBD system in the containment fulfills the safety function of providing an extension of the containment liner. The system is required to maintain the secondary system pressure boundary for Appendix R safe-shutdown and SBO events. Some portions of the SGBD system have the potential for spatial interaction with other safety related equipment.

SGBD is routed to the startup blowdown flash tank during startup or under abnormal operating conditions, such as during high condenser in-leakage. The steam produced in the startup blowdown flash tank is vented to the atmosphere through a moisture separator. The water is routed to the screenhouse forebay. When the plant reaches normal full-power operation, the startup blowdown flash tank is taken out of service and the blowdown is routed to the normal blowdown flash tank. The steam from the normal blowdown flash tank is returned to the condensate system through the condensers, and the water is routed to the screenhouse forebay either directly or through mixed-bed demineralizers.

Therefore, the blowdown system is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.3.4-4 of the LRA, the applicant identified the SGBD component types that are within the scope of license renewal and subject to an AMR, including bolting, orifice, piping, tubing, and valve.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and CNP UFSAR Section 10.11 to determine whether there is reasonable assurance that the applicant has identified the SGBD system 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 staff conducted its review in accordance with the SRP-LR, Section 2.3 guidance.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.4.4 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.4.4-1

Section 10.11.2 of the UFSAR states that the SGBD is monitored for radioactivity before reaching either the startup or normal blowdown flash tanks. These radiation monitors close the SGBD system isolation valves upon detection of high radioactivity. However, the staff examined the license renewal drawings for Units 1 and 2 referenced in LRA Section 2.3.4.4 and could not locate radiation monitors upstream of the flash tanks. Therefore, the staff asked the applicant to provide information to locate the radiation monitors and to verify whether pressure boundary retaining housings for these components are subject to an AMR. If not, the applicant was asked to justify the exclusion of these radiation monitors from an AMR, or to revise Table 2.3.4-4 to include these items.

In its response dated May 7, 2004, the applicant stated that, in each unit, monitor DRA-300 (R-19) provides radiation monitoring upstream of the SGBD flash tanks. As shown on license renewal drawings, the individual steam generator sample valves are upstream of the flash tanks. The steam generator samples pass through steam generator sample isolation valves before reaching monitor DRA-300. Radiation monitors 1-DRA-300 and 2-DA-300 do not support a containment isolation function. The SGBD isolation valves are intended for equipment protection, as described in UFSAR Section 5.4.1 under containment isolation system Class F piping, and are not considered containment isolation valves. The closure of these valves upon a high radiation signal provided by the radiation monitors isolates an effluent process flow when high steam generator radioactivity exists. Radiation monitors 1-DRA-300 and 2-DRA-300 pressure retaining boundaries are not subject to aging management since they are located downstream of the seismic Class 1 break at air-operated fail-closed isolation valves

DCR-301, DCR-302, DCR-303, and DCR-304. The radiation monitors are outside of the 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3) pressure boundary as shown on license renewal drawings LRA-1-5141A and LRA-2-5141A. Therefore, the radiation monitors are not subject to an AMR and are not included in LRA Table 2.3.4-4.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.4-1 acceptable, because it adequately explained that the radiation monitors are not included within the system evaluation boundary and are therefore not within the scope of license renewal. Therefore, the staff's concerns described in RAI 2.3.4.4-1 are resolved.

RAI 2.3.4.4-2

For those SSCs within the scope of license renewal in accordance with 10 CFR 54.4, 10 CFR 54.21(a)(1) requires the applicant to identify and list those SCs subject to an AMR. The staff could not determine whether the applicant considered all the SSCs within the scope of license renewal to satisfy this requirement.

Section 2.1.2.1.1 of the LRA states that the identification of components subject to an AMR begins with the determination of the system evaluation boundary. The system evaluation boundary includes those portions of the system that are necessary to ensure that the intended functions of the system will be performed. Components needed to support each of the system-level intended functions identified in the scoping process are included within the system evaluation boundary.

The staff could not verify whether the applicant identified all the components that perform an intended function because it did not identify the components within the system evaluation boundary in the LRA. The staff must verify this information to effectively review the LRA using the SRP-LR.

Therefore, the staff asked the applicant to confirm that the system components marked on license renewal drawings for the SGBD system depict all the components that perform an intended function. If not, the applicant was asked to provide a list of those components that perform an intended function but are not marked on license renewal drawings, or provide revised drawings as needed to include the additional components.

In its response dated May 20, 2004, the applicant stated that system components highlighted on license renewal drawings include all components that perform an intended function, with the exception of structures, active and short-lived components, and those components that are in scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2). Active components that were screened out and not highlighted on flow diagrams are those that do not meet the 10 CFR 54.21(a)(1)(i) criteria, as identified in Appendix B to NEI 95-10, including items such as instrumentation, motors, and valve operators.

Marking up the license renewal drawings to show components that are within scope and subject to an AMR based solely on the criteria of 10 CFR 54.4(a)(2) would be of minimal value, if any, since such components are included if they are installed in the area of safety related SSCs, and proximity to safety related SSCs cannot be determined from functional flow diagrams. The applicant's response to RAI 2.3.3.11-1 provides a list of SGBD component types that perform 10 CFR 54.4(a)(2) intended function.

The SGBD license renewal drawings do not depict any short-lived components that perform a 10 CFR 54.4 intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.4-2 acceptable, because it adequately identified and described the components. Therefore, the staff's concerns described in RAI 2.3.4.4-2 are resolved.

RAI 2.3.4.4-3

Section 2.1.2.1.2 of the LRA states that the applicant created the license renewal drawings by marking mechanical flow diagrams to indicate only those components within the system evaluation boundaries that require an AMR. Components that are within the scope of license renewal based solely on the criteria of 10 CFR 54.4(a)(2) are not generally indicated on the drawings but are described in LRA Section 2.3 and listed in LRA Table 3.3.2-11.

Pursuant to 10 CFR 54.21(a)(1), the applicant must identify and list those SCs subject to an AMR. The staff's position is that the applicant failed to met this requirement because the components of the SGBD system meeting the criteria of 10 CFR 54.4(a)(2) are neither identified on drawings nor listed. The applicant included these as component types instead of individually listed components. Therefore, the staff asked the applicant to confirm that the SGBD system components marked on license renewal drawings depict all the components within the SGBD system that meet the criteria of 10 CFR 54.4(a)(2). If not, the applicant should provide a list of these components that are not marked on license renewal drawings or provide revised drawings as needed to include the additional components.

In its responses dated May 20 and September 2, 2004, the applicant stated that LRA tables group the components meeting the criteria for 10 CFR 54.4(a)(2) as component types instead of as individual components.

The 10 CFR 54.4(a)(2) identification process, as described in response to RAI 2.3.3.11-2, designates nonsafety-related systems and components with the potential for spray or leakage that could prevent safety-related systems and components from performing their required safety function. Conservatively, the applicant determined all nonsafety-related components containing liquid or steam located in the auxiliary building and screenhouse to be subject to an AMR unless no safety-related equipment is in the area.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.4-3 acceptable because it provided an adequate explanation in the responses to RAI 2.3.3.11-2 regarding the components in the auxiliary building and screenhouse that are subject to an AMR based on the criteria of 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.4-3 is resolved.

2.3.4.4.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI response, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the SGBD system. Therefore, the staff concludes that the applicant adequately identified the SGBD system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SGBD system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.5 Main Turbine

2.3.4.5.1 Summary of Technical Information in the Application

In Section 2.3.4.5 of the LRA, the applicant described the main turbine (MT) system. The MT generator converts the thermal energy of steam into mechanical shaft power used to rotate the generator field. The MT system includes the MT and the following supporting systems:

- main turbine lubricating oil
- main turbine lubricating oil cleanup
- main turbine steam seals
- turbine controls
- electrohydraulic controls
- turbine supervisory instruments

The capability to trip the MT is a required function in support of the ATWS and SBO events. This is the only intended function of the mechanical components of the MT.

Therefore, the MT is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(3).

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 and CNP UFSAR Section 10.3.1 to determine whether there is reasonable assurance that the applicant identified the MT system 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 staff conducted its review in accordance with the SRP-LR, Section 2.3 guidance.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of the LRA Section 2.3.4.5 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, the staff issued RAIs to the applicant concerning these specific issues to determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses are described below.

RAI 2.3.4.5-1

Section 2.3.4.5 of the LRA states that the only intended function of the mechanical components of the MT system is to effect a turbine trip in response to an ATWS or SBO event. Since a pressure boundary failure of the mechanical components of the control system will automatically cause a trip, the pressure boundary intended function of these components is not required following these events. Section 2.3.4.5 of the LRA also states that no passive mechanical component of the MT system is subject to an AMR.

In accordance with the criteria of 10 CFR 54.4(a)(3), the mechanical components of the MT control system should be within the scope of license renewal. Since LRA Section 2.3.4.5 does not reference or provide any boundary drawings that show these components, the staff could not determine whether the applicant identified all components that should be subject to an AMR. Therefore, the staff asked the applicant to provide a drawing or a text description of the MT system to identify the mechanical components of the turbine control system that are subject to an AMR.

In its response dated May 7, 2004, the applicant stated that the intended function of the mechanical components of the MT system is to effect a turbine trip in response to an ATWS or SBO event. In accordance with the criteria of 10 CFR 54.4(a)(3), the turbine control system is within the scope of license renewal. The turbine control system is a hydraulic system that trips the turbine by dumping hydraulic fluid from the turbine control valve actuators. Since a pressure boundary failure of the mechanical components of the control system will automatically cause a trip, the pressure boundary of these components is not required to support the system intended function. Mechanical components that actually dump the hydraulic fluid are active and do not require an AMR. Since passive mechanical components have no intended function, they also require no AMR. Therefore, no mechanical components of the turbine control system are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.5-1 acceptable because it explains that the MT system has no passive components within the scope of license renewal; thus, no AMR is required. Therefore, the staff's concerns described in RAI 2.3.4.5-1 are resolved.

2.3.4.5.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI response, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the MT system. Therefore, the staff concludes that the applicant adequately identified the MT system SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the MT system SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results—Structures

This section documents the staff's review of the applicant's scoping and screening results for structures. Specifically, this section discusses the following structures:

- containment
- auxiliary building
- turbine building and screenhouse
- yard structures
- structural commodities

In accordance with the requirements stated in 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived structures and structural components that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that the applicant did not omit any structures and structural components that meet the scoping criteria and are subject to an AMR.

The staff performed its evaluation of the information provided in the LRA in the same manner for all SCs. The review sought to determine if the applicant identified the components and supporting structures for a specific containment, structure, or containment support that appear to meet the scoping criteria specified in 10 CFR Part 54 as within the scope of license renewal in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

To perform its evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing its review on components that have not been identified as within the scope of renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each structure or structural component to determine whether the applicant omitted system components with intended functions delineated under 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the licensing basis documents to determine whether the LRA specifies all intended functions delineated under 10 CFR 54.4(a). If the staff identified any omissions, it requested additional information to resolve the discrepancy.

Once the staff completed its review of the scoping results, it evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether the functions are performed with moving parts or a change in configuration or properties, or if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that do not meet either of these criteria, the staff sought to confirm that these structures and structural components are subject to an AMR, as required by 10 CFR 54.21(a)(1). If the staff identified discrepancies, it requested additional information to resolve them.

In LRA Table 2.2-3, the applicant identified the following structures as within the scope of license renewal:

- containment (LRA Section 2.4.1)
- auxiliary building (LRA Section 2.4.2)
- turbine building and screenhouse (LRA Section 2.4.3)
- yard structures (LRA Section 2.4.4)
  - fire protection pump house
  - flood protection earth (under roadway)
  - gas bottle storage tank foundation

— roadway
— security diesel generator room
— switchyard control house
— tank area pipe tunnel (condensate storage tank, refueling water storage tank, and emergency diesel generator piping tunnel)
— tank foundations (condensate storage tank)
— tank foundations (FP water storage tank)
— tank foundations (primary water storage tank)
— tank foundations (refueling water storage tank)
— tower (Unit 1 power delivery to switchyard)
— tower (Unit 2 power delivery to switchyard)
— transformer pedestals
— trench from switchyard to startup transformers (duct bank)

Although not listed in LRA Table 2.2-3, the applicant also defined a structural commodities group in LRA Section 2.4.5.

Sections 2.4.1, 2.4.2, 2.4.3, 2.4.4, and 2.4.5 of the LRA, and the associated LRA Tables 2.4-1, 2.4-2, 2.4-3, 2.4-4, and 2.4-5, provide the detailed lists of structures and structural components included in each of these five groups.

RAI 2.4-1

In LRA Table 2.2-4, the applicant identified structures that are not within the scope of license renewal. Based on its review of this table, the staff requested the following additional information related to scoping in RAI 2.4-1:

(a) LRA Table 2.2-4 identifies structures that are not within the scope of license renewal. The note at the top of the table states "The UFSAR does not contain details of these structures." It is not obvious to the staff that all of the listed structures serve no intended function. Please provide (1) a description of the containment access building, gas cylinder storage building, hazardous storage building, and the loop feed enclosure; and (2) the technical basis for the determination that they are not within the scope of license renewal.

(b) LRA Table 2.2-4 identifies the "Switchyard tower and pedestal for Unit 2 power delivery" as not being within the scope of license renewal. However, LRA Table 2.2-3 and LRA Section 2.4.4 "Yard Structures" identify "Tower: Unit 2 power delivery to switchyard" as within scope and subject to aging management review. Please resolve this apparent discrepancy.

(c) Verify that seismic II/I considerations are not applicable to any of the structures listed in LRA Table 2.2-4 (*i.e.*, meteorological and microwave towers).

(d) Verify that there is no site drainage or dewatering system that is relied on to control the groundwater level. If there is such a system, describe it and identify whether it is within the scope of license renewal. Provide the technical basis for either including it in or excluding it from the scope of license renewal. If within the scope, identify the applicable AMR references in LRA Section 3.

By letter dated May 7, 2004, the applicant submitted the following response to RAI 2.4-1:

(a) The containment access building, gas cylinder storage building, and the hazardous storage building do not perform intended functions. The containment access building is located east of the auxiliary building crane bay. It houses the offices for the Radiation Protection Department and serves as the primary entry/exit point for the radiologically restricted area. The gas cylinder storage building stores miscellaneous gas cylinders and is located on grade south of the Unit 2 turbine building. The hazardous storage building is a modular building, located west of the Unit 1 turbine building, in which 55-gallon drums of chemical waste are stored.

These three structures are not connected to seismic structures and do not provide:

(1) structural support or functional support for safety related equipment;
(2) shelter or protection for safety related equipment;
(3) structural or functional support for non-safety related equipment whose failure could directly prevent satisfactory accomplishment of required safety related functions;
(4) missile barriers (internally or externally generated);
(5) flood protection barriers (internal or external flooding event);
(6) rated fire barriers to confine or retard a fire from spreading to or from adjacent regulatory fire areas or regulatory fire zones; or
(7) structural or functional support for components credited for regulated events.

Note that the "Gas bottle storage tank foundation" listed in LRA Table 2.2-3, the "Gas bottle storage tank rack" listed in LRA Table 2.4-4, and the "Gas bottle storage tank rack and foundation" listed in LRA Section 2.4.4 refer to the nitrogen bulk storage tank foundation and racks, which is in scope for 10 CFR 54.4(a)(3) requirements, and not to the gas cylinder storage building discussed above.

The inclusion of the loop feed enclosure in LRA Table 2.2-4 is an error. The loop feed enclosure is in the scope of license renewal as part of the offsite power (OFPW) system (which was included based on NRC guidance pertaining to station blackout). The OFPW system provides the electrical interconnections between the offsite network and the station auxiliary buses, as well as electrical interconnections among other buildings and facilities located on the CNP site. The concrete portion of the loop feed enclosure is covered in LRA Table 2.4-4, under line item "Trench from switchyard to start-up transformers (duct bank)." The enclosure itself is covered in LRA Table 2.4-5 under line item "Electrical instrument panels and enclosures."

(b) The inclusion of "Switchyard tower and pedestal for Unit 2 power delivery" in LRA Table 2.2-4 is an administrative error. The same item is correctly identified in LRA Table 2.2-3.

(c) During the scoping process, Seismic II over I considerations were verified as not applicable to structures that were correctly listed in LRA Table 2.2-4, including meteorological and microwave towers.

(d) CNP does not have any site drainage or dewatering system that is relied on to control the groundwater level.

The staff reviewed the applicant's response and found that it provides an adequate technical basis for the applicant's scoping determinations. In response to part (a) of the RAI, the applicant provided adequate justification that the containment access building, gas cylinder storage building, and hazardous storage building are not within the scope of license renewal. The applicant indicated that the loop feed enclosure is within scope and is listed in LRA Table 2.2-4 in error. In response to part (b) of the RAI, the applicant acknowledged that the "Switchyard tower and pedestal for Unit 2 power delivery" is within scope and is listed in LRA Table 2.2-4 in error. In response to part (c) of the RAI, the applicant verified that seismic II/I considerations do not apply to structures correctly listed in LRA Table 2.2-4. (The loop feed enclosure and "Switchyard tower and pedestal for Unit 2 power delivery" do not belong in the table.) In response to part (d) of the RAI, the applicant verified that there is no system relied on to control the ground water level. Therefore, the staff's concerns described in RAI 2.4-1 are resolved.

RAI 2.4-4

Load handling systems have components that are both mechanical and structural in nature. The structural components are passive and long-lived. If a specific load handling system serves an intended function, then it is subject to an AMR. To ensure a complete understanding of the CNP scoping, screening, and AMR results for load handling systems, the staff requested the following additional information related to scoping of load handling systems in RAI 2.4-4:

> It is not clear to the staff about the scope of load handling systems included in the D.C. Cook license renewal scope. LRA Section 2.3.3.12, "Material/Equipment Handling" and "Refueling", identify specific cranes that are in the scope of license renewal, and refer to LRA Section 2.4 for the evaluation. LRA Sections 2.4.1, 2.4.2, 2.4.3, and 2.4.5 all identify load handling systems under "Evaluation Boundaries" and/or in the associated Table 2.4-x. However, there is not a one-to-one correspondence between all of the cranes listed in LRA Section 2.3.3.12 and the information in LRA Section 2.4. Also, it is not clear

if there are additional load handling systems in the LR scope and covered by LRA Section 2.4.

With the concerns stated above, the applicant is requested to: (1) provide a listing of all load handling systems in the LR scope; (2) identify specific components that are subject to an AMR, for each in-scope load handling system; (3) identify the specific line item in LRA Tables 2.4-1, 2.4-2, or 2.4-5 that covers each component; and (4) identify the applicable AMR reference for each component.

By letter dated May 7, 2004, the applicant submitted the following response to RAI 2.4-4:

(1) LRA Section 2.3.3.12 provides a general description of the material handling system and provides a reference to LRA Section 2.4 for cranes that are evaluated as structural components. Load handling systems that perform an intended function for license renewal are:

- Ice condenser equipment access end wall cranes
- Ice condenser bridge cranes
- Polar cranes
- Auxiliary building cranes
- Spent fuel cranes
- Emergency diesel generator cranes
- Auxiliary building hoists:
  - Motor driven and turbine driven auxiliary feed pump room manual hoists
  - Reactor coolant filter and seal water return filter hoists
  - Concentrates, seal water injection, and ion exchange filters hoists
  - Reciprocating charging pump room hoists
  - Centrifugal charging pump room hoists
  - Safety injection pump room hoists
  - Containment spray pump room hoists
  - Residual heat removal pump room hoists
  - Main steam stop enclosure hoists
  - Recirculation valve enclosure hoists

(2) Crane rails, girders, and their associated supports and anchorages are subject to aging management review for all in-scope load handling systems.

(3) The following table provides the cross-reference to specific line items in LRA tables.

Load Handling System	LRA Table Cross Reference	Table Line Item
Ice condenser equipment access end wall cranes	Table 2.4-1 and Table 3.5.2-1	Ice condenser bridge cranes, crane rails, and supports
Ice condenser bridge cranes	Table 2.4-1 and Table 3.5.2-1	Ice condenser bridge cranes, crane rails, and supports
Polar cranes	Table 2.4-1 and Table 3.5.2-1	Polar cranes, crane rails, and supports
Auxiliary building cranes	Table 2.4-2 and Table 3.5.2-2	Cranes, rails, and supports
Spent fuel cranes	Table 2.4-2 and Table 3.5.2-2	Cranes, rails, and supports
Emergency diesel generator cranes	Table 2.4-2 and Table 3.5.2-2	Cranes, rails, and supports
Auxiliary building hoists listed in response to sub-part (1) of this question	Table 2.4-5 and Table 3.5.2-5	Cranes, rails, and girders

(4) The applicable aging management review reference in the LRA for each component is shown in the LRA Section 3 tables listed in sub-part (3) of this question.

The staff reviewed the applicant's initial response and found that it adequately describes the scoping, screening, and AMR for load handling systems, with one exception. In telephone conference calls with the applicant held on May 17, 2004, and May 21, 2004, the staff requested that the applicant submit supplemental information to clarify the crane active and passive components. The applicant stated that the crane itself is an active component. All other components (*i.e.* rail, girders) are passive parts. The applicant submitted the following supplemental response to RAI 2.4-4, by letter dated August 11, 2004:

> The applicant's original response to paragraph (2) of RAI 2.4-4, provided in the May 7, 2004, RAI response letter, ...identified some of the load handling system components that are subject to aging management review. This supplemental response provides clarification to the original RAI 2.4-4 response by revising and expanding paragraph (2) of the original RAI 2.4-4 response to clearly identify the in-scope load handling system structural components that perform a license renewal intended function:
>
> (2) The structural components (including crane rails, girders, bridge, trolley, monorails, and their associated supports and anchorages) of the in-scope load handling systems are subject to aging management review.

The staff reviewed the applicant's supplemental response and finds that it adequately identifies the passive components of cranes that are within scope and subject to an AMR. Therefore, the staff's concerns described in RAI 2.4-4 are resolved.

2.4.1 Containment

2.4.1.1 Summary of Technical Information in the Application

In Section 2.4.1 of the LRA, the applicant identified the SCs of the containment that are subject to an AMR for license renewal. The containment structure serves as both a biological shield and a pressure container during a LOCA or steamline break accident. The containment structure, including all penetrations and the interior structure, is part of the ESF incorporated in the design of CNP and is classified as a safety related, seismic Class I structure. CNP Units 1 and 2 use ice condenser reactor containment systems. The containment building is a reinforced concrete structure consisting of a vertical cylinder, a hemispherical dome, and a flat base slab. A steel liner is attached to the inside face of the concrete (shell, dome, and the base slab) to ensure a high degree of leak tightness. The interior of the containment structure is divided into three compartments:

(1) a lower compartment that houses the reactor and the RCS

(2) an intermediate compartment that houses the energy absorbing ice bed (ice condenser compartment)

(3) an upper compartment that accommodates the air displaced from the other two compartment volumes during an accident condition

The ice condenser is essentially a well-insulated cold storage room that maintains ice in an array of vertical cylindrical columns. The ice columns are formed by perforated sheet metal baskets of ice, with the space between columns forming the flow channels for steam and air. The ice condenser is contained in the annulus formed by the containment vessel wall and the crane wall, circumferentially over a 300-degree arc. The refueling canal and equipment hatch are located in the remaining 60-degree arc. The ice condenser compartment extends from below the operating deck to the top of the crane wall. The uppermost section of the ice condenser forms a plenum, which accommodates the air cooling equipment and provides access for ice loading and maintenance. A small bridge crane is provided at the top of the ice condenser compartment for construction and maintenance purposes.

In the event of an accident, lower inlet doors located below the operating deck at the bottom of the ice condenser open because of the pressure rise in the lower compartment. This allows steam to flow from the lower compartment into the ice condenser compartment. The steam is condensed as it enters the ice condenser compartment, thus limiting the peak pressure in the containment. (The condensation of steam in the ice bed limits the containment pressure to a value substantially lower than that of a comparable dry-type containment under the same conditions.) Upon pressure increase in the ice compartment, the intermediate and top doors in the ice condenser compartment open to allow air to flow into the upper compartment. Seals are provided on the boundary of the lower and upper compartments and on the hatches in the operating deck to limit steam bypassing the ice condenser.

The primary safety intended function of the containment is to limit the release of radioactive fission products following an accident, thereby limiting the dose to the public and control room operators. The containment structure also provides physical support for itself, the RCS, ESF, and other systems and equipment located within the structure. The exterior walls and dome provide protection for the reactor vessel and all other safety related SSCs inside the containment from missiles (internal and external) and natural phenomena.

The containment includes nonsafety related commodity groups that must maintain mechanical and structural integrity so that nearby safety related equipment is not adversely affected. The containment also supports, protects, and provides penetrations for safe-shutdown equipment required under Appendix R to 10 CFR Part 50, environmentally qualified electrical equipment, and equipment used to cope with an SBO.

Therefore, the containment is within the scope of license renewal, based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.4-1 of the LRA, the applicant identified the containment component types that are within the scope of license renewal and subject to an AMR. Those made of steel include air lock doors; air lock hinges, locks, and closing mechanisms; containment liner and associated anchorage; containment penetrations (mechanical and electrical); CRDM support structure; divider barrier access doors and associated framing; divider barrier equipment hatches and associated framing; fuel transfer tube penetration; ice baskets; ice condenser bridge cranes, crane rails, and supports; ice condenser intermediate deck door frames; ice condenser lattice frame; ice condenser lower deck door frames; ice condenser lower support structure; ice condenser turning vanes; ice condenser wall duct panels; polar cranes, crane rails, and supports; pressurizer supports; reactor cavity missile block embedded steel and associated framing; RCP supports; reactor vessel supports; removable gate (bulkhead); seal table; steam generator enclosure permanent interior form plate; steam generator supports; structural steel framing (including embedded steel); sump screens (coarse) and associated framing; sump screens (fine); threaded fasteners (CRDM support structure); threaded fasteners (ice basket); and threaded fasteners (RCS component support (reactor vessel, steam generators, RCPs, pressurizer)).

Those made of concrete include the containment base slab foundation, containment dome, containment operating deck, containment wall, crane wall (upper) and ice condenser end walls, exhaust dome and exhaust duct, fuel transfer canal walls and floodup overflow structure, ice condenser support slab, ice condenser wear slab, lower containment concrete walls and floor slabs, pressurizer enclosure, reactor cavity missile blocks, regenerative heat exchanger room wall, and steam generator enclosures.

Those made of rubber include air lock seals, reactor pit membrane waterproofing, and removable gate (bulkhead) seals.

Finally, those made of other materials include the ice condenser intermediate and upper deck curtains.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 and CNP UFSAR Chapter 5 to determine whether the applicant identified the containment components within the scope of license renewal and subject to AMR. The staff conducted its review in accordance with the guidance described in Section 2.4 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.4.1 identified several areas in which it needed additional information to complete its evaluation of the applicant's scoping and screening results. Therefore, the staff issued RAIs 2.4-2 and 2.4-5 to the applicant concerning these specific issues to determine whether it properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). By letter dated May 7, 2004, the applicant responded to these two RAIs.

The following summarizes the staff's concerns, the applicant's responses, and the staff's evaluation of these two RAIs.

RAI 2.4-2

Based on its review of LRA Sections 2.1, 2.2, 2.3, 2.4, and 2.5, the staff issued RAI 2.4-2, as follows, which identified the following issues related to scoping and screening:

a. It is not clear to the staff if the applicant has addressed thermal insulation on piping and structures in its scoping and screening evaluation.

b. LRA Section 2.4.1 (Page 2.4-2) states that: "Seals are provided on the boundary of the lower and upper compartments and on the hatches in the operating deck to limit steam bypassing the ice condenser." However, LRA Table 2.4-1 does not appear to include these seals.

c. LRA Section 2.4.1 identifies the equipment hatch as part of the containment structure evaluation boundary. However, LRA Table 2.4-1 does not appear to include the equipment hatch.

For each issue above, the applicant is requested to (1) identify if it is within the scope of license renewal; (2) if not within the scope of license renewal, provide the technical basis for that determination; (3) if within the scope of license renewal, identify the specific table and row in LRA Section 2.3 or 2.4 that includes the item; and (4) if within the scope of license renewal, identify the location in LRA Section 3 that addresses the AMR for the item.

The applicant responded to RAI 2.4-2 as follows:

a. For information related to thermal insulation on piping, refer to the RAI 2.1-5 response.

   Structural thermal insulation is addressed in the scoping and screening evaluation as follows:

   (1) The thermal barriers for the ice condenser, wall duct panels, intermediate and upper deck curtains, and concrete walls are within the scope of license renewal.

   (2) Not applicable—within the scope of license renewal.

   (3) The thermal barriers for the ice condenser, wall duct panels, intermediate and upper deck curtains, and concrete walls are included in the "Ice condenser intermediate and upper deck curtains" entry in LRA Table 2.4-1 on page 2.4-16.

   (4) The "Ice condenser intermediate and upper deck curtains" entry in LRA Table 3.5.2-1 on page 3.5-40 addresses the aging management review for these items.

b. Seals that provide a boundary between the lower and upper compartments are of three types.

   (1) Divider barrier seals between the bottom of the ice condenser compartment slab and the containment wall and up the sides of the ice condenser end walls.

   (2) Divider barrier hatch seals provided on the hatches in the operating deck.

   (3) Divider barrier penetration seals installed around penetrations and openings through the divider barrier.

   For these seals,

   (1) All three types of seals described above are within the scope of license renewal. The seals are sub-components within the containment structure and are not explicitly called out. LRA Table 2.2-3 lists the containment as a structure within scope.

   (2) Not applicable—within the scope of license renewal.

   (3) The first two types of seals, divider barrier seals and the divider barrier hatch seals, are not listed in LRA Table 2.4-1 as subject to aging management review since they are considered short-lived. The determination that the divider barrier seals and the divider barrier hatch seals are short-lived is based on guidance in the SOC and in NUREG-1800.

Statements of Consideration (SOC) on "Long-Lived" SRP Section 2.1.3.2.2:

> "It is important to note, however, that the Commission has decided not to generically exclude passive structures and components that are replaced based on performance or condition from an [AMR]...such generic exclusion is not appropriate....However, the Commission does not intend to preclude a license renewal applicant from providing site-specific justification in a license renewal application that a replacement program on the basis of performance or condition for a passive structure or component provides reasonable assurance that the intended function of the passive structure or component will be maintained in the period of extended operation."

Specific Staff Guidance on "Consumables" SRP Table 2.1-3—

> "...The consumables in category (c) are short-lived and periodically replaced, and can be excluded from an AMR on that basis. Likewise, the consumables that fall within category (d) are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from AMR under 10 CFR 54.21(a)(1)(ii)."

The divider barrier seals are inspected and replaced based on their condition in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.9. The divider barrier hatch seals are visually inspected before final closure each outage and replaced as needed and are inspected every ten years per CNP Technical Specification Surveillance Requirement 4.6.5.5.2. Therefore, these seals are short-lived and not subject to aging management review. The divider barrier penetration seals are listed in the "Divider barrier penetration seals" entry in LRA Table 2.4-5 on page 2.4-22.

(4) The "Divider barrier penetration seals" entry in LRA Table 3.5.2-5 on page 3.5-66 addresses the aging management review for divider barrier penetration seals.

c. The equipment hatch is grouped with the personnel airlocks in the component type "Air lock doors." The equipment hatch is located near the top of the fuel transfer canal. One personnel access opening is located within the equipment hatch. The other is located at the instrument room, El. 612'. The component type "Air lock doors" corresponds to items 3.5.1-4 and 3.5.1-5 "Personnel airlock and equipment hatch" in LRA Table 3.5-1 on page 3.5-17.

(1) The equipment hatch is within the scope of license renewal and is subject to aging management review.

(2) Not applicable—within the scope of license renewal.

(3) The equipment hatch is included in component type "Air lock doors" entry in LRA Table 2.4-1 on page 2.4-14.

(4) The "Air lock doors" entry in LRA Table 3.5.2-1 on page 3.5-27 addresses the aging management review for the equipment hatch.

The following summarizes the staff's evaluation of the applicant's response.

Part (a)
In its response to part (a) of the RAI, the applicant referred to its response to RAI 2.1-5 for information related to thermal insulation on piping. In its response to RAI 2.1-5, the applicant stated the following:

> Insulation that functions only to maintain the environment (temperature) during normal operation does NOT perform an intended function as described in 10 CFR 54.4. An example of such insulation is that which is installed on hot piping in containment. Degradation of this insulation could result in local concrete temperature exceeding the temperature assumed for the environment in the aging management review. However, maintaining the environment assumed for the aging management review is not an intended function, as described in 10 CFR 54.4.

This quote from the RAI 2.1-5 response presents a good case for including the thermal insulation within the scope of license renewal in accordance with 10 CFR 54.4(2).

In its response to RAI 2.1-5, the applicant erroneously paraphrased and interpreted the Generic Aging Lessons Learned (GALL) Report and SRP-LR recommendations for aging management of concrete exposed to elevated temperature, indicating that the Structures Monitoring Program is sufficient to manage such aging. This is not the case for the hot containment penetrations, which are the most susceptible locations for this type of degradation (see GALL Report, Chapter II A1, Item A1.1-h (page II A1-8), and SRP-LR Section 3.5.3.2.1.3 (page 3.5-7) for containment; see GALL Report Chapter III A1, Item A1.1-j (page III A1-9), and SRP-LR Section 3.5.3.2.2.1 (page 3.5-8) for Class I structures).

In its response to RAI 2.1-5, the applicant closed with an argument that there are no AERMs for insulation in an indoor environment and quoted from the staff SER for the Calvert Cliffs license renewal (NUREG-1705) to support its argument.

If the applicant does not credit thermal insulation to maintain the temperature of concrete below degradation threshold levels and concludes that the concrete may be subject to long-term overheating if the insulation degrades, then the applicant must provide a plant-specific AMP to detect any change in concrete material properties resulting from long-term exposure to elevated temperatures. The staff concluded during the development of the GALL Report that visual examination is not sufficient to detect change in material properties of concrete resulting from long-term exposure to elevated temperatures.

Part (b)
In its response to part (b) of the RAI, the applicant identified three types of divider barrier seals:

(1) divider barrier seals between the bottom of the ice condenser compartment slab and the containment wall and up the sides of the ice condenser walls

(2) divider barrier hatch seals provided on the hatches in the operating deck

(3) divider barrier penetration seals installed around penetrations and openings through the divider barrier

The applicant stated that all three types of seals are within the scope of license renewal. The staff finds this acceptable. However, the applicant indicated that only the divider barrier penetration seals are subject to an AMR, because it considers the first two types of seals to be short-lived. The applicant stated that this determination "is based on guidance in the Statements of Consideration and in NUREG-1800" and selectively quotes from SRP Section 2.1.3.2.2 (Statements of Consideration on "long-lived") and SRP Table 2.1-3 (guidance on "consumables") to support its determination.

Based on review of the complete text of these SRP sections, the applicant's interpretation of the Statements of Consideration is questionable, and the applicant erroneously quoted from the discussion of category (c) and (d) consumables, while seals are category (a) consumables.

The applicant stated the following:

> The divider barrier seals are inspected and replaced based on their condition in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.9. The divider barrier hatch seals are visually inspected before final closure each outage and replaced as needed and are inspected every ten years per CNP Technical Specification Surveillance Requirement 4.6.5.5.2. Therefore, these seals are short-lived and not subject to aging management.

The 10 CFR 54.21(a)(1)(ii) criterion for inclusion within the scope of license renewal is SCs "that are not subject to replacement based on a qualified life or specified time period." The two types of seals in question are inspected and replaced based on their condition, which is exactly what aging management for license renewal is intended to accomplish. It would be more appropriate for the applicant to credit the current inspection activities and technical specification requirements as the license renewal AMP for these seals than to claim that they are the basis for exclusion from the scope of license renewal.

Part (c)
The applicant's response to part (c) of the RAI is acceptable because it clarifies that the equipment hatch is included in the license renewal scope.

The staff did not consider the applicant's responses to RAI 2.4-2 parts (a) and (b) to be acceptable, because they do not provide sound technical bases for the applicant's conclusions.

In telephone conference calls with the applicant held on May 17, 2004, May 21, 2004. and November 10, 2004, the staff described its concerns about parts (a) and (b) of the response, and requested that the applicant submit additional information to address the concerns. The applicant submitted the following supplemental responses to RAI 2.4-2 parts (a) and (b), by letter dated November 18, 2004:

Supplementary Response to RAI 2.4-2 part (a):

> [Note: The applicant has addressed this issue in a supplementary response to RAI 2.1-5 on the same subject]
>
> The NRC Staff requested I&M to clarify whether piping thermal insulation serves an intended function in accordance with 10 CFR 54.4, and to provide the basis for the determination as to whether this piping thermal insulation requires aging management. In an RAI response dated August 11, 2004, ...I&M stated that piping insulation is not in scope and not subject to aging management review, except in certain specific applications where the insulation is required to maintain post-accident temperature in areas housing safety-related equipment. The NRC Staff has indicated a need for additional information regarding the review of piping thermal information. Based on a conference call with the NRC Staff on November 10, 2004, I&M understands that the specific information required pertains to the review of the piping thermal insulation at containment penetrations.
>
> Thermal insulation on hot piping at containment penetrations does not meet the scoping criteria of 10 CFR 54.4. The insulation on hot containment piping penetrations is not required to ensure the functions of 10 CFR 54.4(a)(1) are accomplished or to demonstrate compliance with NRC regulations identified in 10 CFR 54.4(a)(3). The insulation does not meet 10 CFR 54.4(a)(2), as its failure will not prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1). Insulation on hot piping at containment penetrations does support maintaining the environment for surrounding structural elements. However, maintaining the environment during normal operation is not an intended function identified in 10 CFR 54.4(a)(1). Therefore, thermal insulation on hot piping at containment penetrations does not meet the scoping criteria of 10 CFR 54.4. This is consistent with the previously approved staff position documented in NUREG-1766, Safety Evaluation Report Related to the License Renewal of North Anna Nuclear Station, Units 1 and 2, and Surry Nuclear Power Station, Units 1 and 2.
>
> Notwithstanding the above, I&M agrees to include the insulation on hot containment piping penetrations in the scope of license renewal. The intended function that was applied to the insulation is to prevent excessive heat transmission to the containment concrete surrounding the piping penetrations. The insulation is encapsulated with stainless steel jacketing in the annulus between the penetration piping and the penetration sleeve. There are no applicable aging effects for insulation in the indoor air environment. A review of CNP operating experience for the past five years verified that the plant has not experienced aging-related degradation of piping insulation in dry indoor environments. Therefore, based upon the material, environment, and operating

experience, the insulation is not expected to degrade, and an AMP is not required.

The staff finds the applicant's supplementary response to RAI 2.4-2 part (a) acceptable because the applicant has included the insulation on hot containment piping penetrations in the scope of license renewal.

Supplementary Response to RAI 2.4-2 part (b):

> In RAI responses dated May 7, 2004, and August 11, 2004,...I&M stated that the divider barrier seals and divider barrier hatch seals are short-lived and not subject to aging management review because they are periodically inspected in accordance with Technical Specifications 4.6.5.9 and 4.6.5.5.2, respectively. I&M's position was based on NRC statements regarding NUREG-1800, Section 2.1.3.2.2, "Long-Lived," in the Statements of Consideration for the Final License Renewal Rule. Upon further consideration, I&M has determined that it would be more appropriate to credit inspection activities that implement plant Technical Specification requirements as the license renewal AMP for the divider barrier *seals and divider barrier hatch and personnel access seals than to credit the* Technical Specification requirements as the basis for exclusion from aging management review.
>
> To implement this change, the Updated Final Safety Analysis Report (UFSAR) supplement for the Structures Monitoring – Divider Barrier Seal Inspection Program provided in LRA Sections A.2.1.37 and the affected program element descriptions from LRA Section B.1.34 are modified as provided below. New text is *italicized*, as follows:
>
> **A.2.1.37 Structures Monitoring – Divider Barrier Seal Inspection Program**
>
> The Divider Barrier Seal Inspection Program detects cracking and change in material properties of *the* elastomeric *divider barrier seals, divider barrier hatch and personnel access door seals, and* pressure seals for penetrations and openings through the containment divider barrier. The program detects aging effects through *analysis of main divider barrier seal test coupons and* visual examination of the *three types of* seals *between the upper and lower containment compartments.*
>
> **B.1.34 Structures Monitoring – Divider Barrier Seal Inspection Program**
>
> **Program Description**
>
> The Divider Barrier Seal Inspection Program is an existing plant-specific program. There is no comparable NUREG-1801 program.
>
> The divider barrier in each containment is the physical boundary that separates upper containment from lower containment. Several containment internal

structures constitute the divider barrier. Elastomeric seals are provided for *the divider barrier that separates the upper and lower containment compartments; and for the personnel access doors, equipment hatches, and* penetrations and openings through the divider barrier where it is necessary to limit potential ice condenser bypass leakage subsequent to a postulated pipe rupture or loss of coolant accident. Cracking and change in material properties are aging effects requiring management for the pressure seals.

Aging Management Program Elements

Scope The scope of this program is the *elastomeric* containment divider barrier *seals; and* elastomeric *hatch seals, personnel access door seals, and* pressure seals around penetrations and openings through the divider barrier.

Parameters Monitored or Inspected Parameters monitored by this program are cracking and change in material properties of elastomeric pressure seals.

Detection of Aging Effects This program detects cracking and change in material properties prior to loss of the pressure seals' intended functions.

In accordance with plant Technical Specifications, (1) the physical properties of the main divider barrier seals are periodically verified through analysis of seal test coupons, and (2) visual inspections of the divider barrier seals and hatch and personnel access door seals are performed to identify apparent deterioration of the seal material. The seals around penetrations and openings (including the bulkhead gate) are visually inspected to ensure the absence of apparent deterioration (cracks or defects). The frequency of *the penetration and openings seals* inspection is at least once every 10 years.

Monitoring and Trending This program monitors aging effects through *analysis of main divider barrier seal test coupons and* visual examination of the *other* seals. The Corrective Action Program provides reasonable assurance that trends entailing repeat failures to meet acceptance criteria will be identified and addressed with appropriate corrective actions.

Acceptance Criteria *The acceptance criteria for the divider barrier seal test coupons is provided in plant Technical Specifications.* The acceptance criteria for *visual* seal inspections are that seals must be free of unacceptable deterioration (excessive cracks or defects) and unacceptable misalignment.

Corrective Actions Discrepancies noted during the inspection are documented in the Corrective Action Program in accordance with the implementing procedure. Specific corrective actions will be implemented in accordance with the CNP Corrective Action Program. *Required actions for failure to meet the Technical Specification surveillance requirements applicable to the main divider barrier seals and divider barrier hatch and personnel access door seals are provided in the plant Technical Specifications.*

In addition, in LRA Tables 2.4-1, on Page 2.4-16 and 3.5.2-1, on Page 3.5-40, the Component entry "Removable gate (bulkhead) seals" is modified to read as follows:

- Main divider barrier seals
- Divider barrier hatch seals
- Personnel access door seals
- Removable gate (bulkhead) seals

The staff finds the applicant's supplementary response to RAI 2.4-2 part (b) acceptable because the divider barrier seals and divider barrier hatch seals are now treated as passive, long-lived components that are subject to an AMR, and the applicant has committed to manage aging of these components under CNP AMP B.1.34, "Structures Monitoring—Divider Barrier Seal Inspection Program."

Therefore, RAI 2.4-2 is considered resolved from the scoping and screening perspective. However, the staff additionally needed to evaluate and accept the applicant's AMR results for thermal insulation. The evaluation was provided in the supplemental response to RAI 2.1-5 (see Section 2.1.3.1.4 for staff evaluation of the supplemental response to RAI 2.1-5).

RAI 2.4-5

Section 2.4 of the LRA does not describe the cable feed-through assembly, which is part of containment electrical penetrations. This assembly serves a pressure boundary intended function. Therefore, the staff requested that the applicant clarify whether the cable feed-through assembly is within the scope of license renewal. If it is within scope, The staff requested that the applicant identify the applicable table number and component name in LRA Section 2.4, and the applicable AMR table number and component name in LRA Section 3.5. If the cable feed through assembly is not within the scope of license renewal, the applicant was asked to provide the justification for its exclusion.

The applicant submitted the following response to RAI 2.4-5, by letter dated May 7, 2004:

> LRA Table 2.1.1 identifies electrical portions of electrical and instrumentation and control penetration assemblies (*i.e.*, electrical penetration assembly cables and connections) as a commodity group that serves an intended function. The cable feed-through assemblies are part of these electrical penetrations, and are therefore in scope for license renewal.
>
> As described in LRA Section 2.1.2.3.3, all electrical penetration assemblies (including the cable feed-through assemblies) are included in the EQ Program. Under the EQ Program, cable feed-through assemblies are subject to replacement based on a qualified life and thus in accordance with 10 CFR 54.21(a)(1)(ii) are not subject to aging management review.
>
> In addition to replacing these components based on a qualified life, the EQ Program also incorporated pressure testing of the cable feed-through assemblies in the qualification of the electrical containment penetrations. Furthermore, while not subject to aging management review, electrical

penetrations are tested in accordance with the requirements of 10 CFR 50 Appendix J. Steel elements of the penetrations were included in the containment aging management review as "Containment penetrations (mechanical and electrical)," listed in LRA Tables 2.4-1 and 3.5.2-1, on pages 2.4-14 and 3.5-28 through 3.5-29.

The staff's evaluation of the applicant's response is described below:

The containment pressure boundary function of the cable feed-through assembly needs to be evaluated as part of the containment structure scope. Appendix J local leak rate testing should be credited (along with any other program the applicant wishes to credit) to manage aging of the cable feed-through assembly for its containment pressure boundary function. The applicant's initial response to RAI 2.4-5 was not acceptable because the applicant did not credit Appendix J local leak rate testing as an AMP for the containment pressure boundary function.

In telephone conference calls with the applicant held on May 17, 2004, May 21, 2004, and November 10, 2004, the staff described its concerns about the response, and requested that the applicant submit additional information to address these concerns. The applicant submitted the following supplemental response to RAI 2.4-5, by letter dated November 18, 2004:

> In response to an NRC staff request pertaining to activities credited to ensure the cable feed-through assemblies will perform their pressure-retaining function throughout the period of extended operation, I&M provided, in a letter dated August 11, 2004, ...a discussion that credited the electrical penetration pressure testing that was performed to satisfy the 10 CFR 50.49 environmental qualification (EQ) requirements and 10 CFR 50 Appendix J containment leakage rate testing. Subsequently, the NRC staff requested that I&M specifically credit 10 CFR 50 Appendix J, Type B testing (or any other AMP) for license renewal, to ensure the pressure boundary integrity of cable feed-through assemblies. The NRC staff further requested that I&M identify the AMP that it is crediting for license renewal.
>
> Pressure testing during environmental qualification of the electrical containment penetrations provides assurance that the pressure boundary integrity of cable feed-through assemblies will be maintained during the period of extended operation. In addition, the Containment Leakage Rate Testing Program, as described in LRA Section B.1.8, is credited with managing the effects of aging on containment electrical penetrations throughout the period of extended operation by providing assurance that leakage through these penetrations does not exceed allowable values. Local leakage rate testing (defined as "Type B testing" in 10 CFR 50 Appendix J), performed under the Containment Leakage Rate Testing Program, provides ongoing confirmation of the integrity of resilient seals around the perimeter of the cable feed-through assemblies. Integrated leakage rate testing (defined as "Type A testing" in 10 CFR 50 Appendix J), performed under the Containment Leakage Rate Testing Program, provides additional confirmation of pressure boundary integrity of the feed-through assemblies.

The staff finds the applicant's supplemental response to be acceptable because the applicant credited 10 CFR Part 50 Appendix J, Type A and Type B testing for license renewal, to ensure the pressure boundary integrity of cable feed-through assemblies. Therefore, the staff's concern described in RAI 2.4-5 is resolved.

2.4.1.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the Containment. Therefore, the staff concludes that the applicant has adequately identified the SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the Containment SCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Auxiliary Building

2.4.2.1 Summary of Technical Information in the Application

In Section 2.4.2 of the LRA, the applicant identified the SCs of the auxiliary building that are subject to an AMR for license renewal. The auxiliary building supports and protects plant equipment, including much of the nuclear steam supply system and other auxiliary systems necessary for the safe operation of CNP, Units 1 and 2. The two CNP units share the auxiliary building, which houses common areas, as well as sections dedicated to each unit. The auxiliary building encloses the fuel storage areas, diesel generator rooms, switchgear rooms, control facilities, and other equipment. The auxiliary building is primarily a T-shaped structure located between the Unit 1 and 2 containment buildings. The auxiliary building also includes the C-shaped structures that border each of the containment buildings and enclose the electrical tunnels and main steamlines. The building is principally a reinforced concrete structure consisting mainly of exterior and interior walls, flat roofs, floor slabs, and a flat foundation mat. The building is classified as a safety related, seismic Class I structure.

The safety intended functions of the auxiliary building are to support and protect safety related plant equipment. The auxiliary building provides physical support for itself, ESF, and other systems and equipment located within the structure. The exterior walls and roofs of the auxiliary building protect against tornado-generated or turbine-generated missiles and provide protection against the weather for systems and equipment within the structure. The auxiliary building includes the SFP and liner, which maintain a sufficient water inventory to provide shielding and cooling for the fuel.

The auxiliary building also supports and protects safe-shutdown equipment related to Appendix R to 10 CFR Part 50 and equipment used to cope with an SBO. The auxiliary building includes nonsafety related commodity groups that must maintain mechanical and structural integrity so that nearby safety related equipment is not adversely affected.

Therefore, the auxiliary building is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.4-2 of the LRA, the applicant identified steel auxiliary building component types that are within the scope of license renewal and subject to an AMR, including block wall grating and framing, cranes and rails and supports, elevator support steel, EDG air intake missile shield framing, EDG air intake missile shield grating, louver framing (EDG and switchgear), missile shield, new fuel storage racks, spent fuel pit steel (including swing gate, attachments, liner, and fuel racks), and superstructure framing,

The applicant also identified concrete components, including the electrical tunnel, elevator masonry block, exterior walls, floor slabs, fuel transfer canal, foundation, interior walls, internal flood curbs, main steamline enclosure, masonry block, roof, spent fuel pit walls and slab, and sump.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 and CNP UFSAR Section 2.9 to determine whether the applicant identified the auxiliary building components within the scope of license renewal and subject to an AMR. The staff conducted its review in accordance with the guidance described in Section 2.4 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff found that the applicant included those portions of the auxiliary building that meet the scoping requirements of 10 CFR 54.4 within the scope of license renewal and identified them as such in LRA Section 2.4.2. Table 2.4-2 of the LRA includes the specific component types that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.4.2.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the auxiliary building. Therefore, the staff concludes that the applicant has adequately identified the SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the auxiliary building SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Turbine Building and Screenhouse

2.4.3.1 Summary of Technical Information in the Application

In Section 2.4.3 of the LRA, the applicant identified the SCs of the turbine building and screenhouse that are subject to an AMR for license renewal. CNP Units 1 and 2 share the turbine building and screenhouse, which house several common areas (such as the makeup plant), as well as sections dedicated to each unit. The turbine building and screenhouse protect plant equipment, including the MT, generator, and auxiliary equipment in the turbine building and the CW pumps and ESW pumps in the screenhouse.

The turbine building is a three-tiered structure that adjoins the auxiliary building. It includes the turbine room, the heater bay areas, and the service bay areas. The turbine building and screenhouse share a masonry wall and a seismic Class I foundation. The AFW and ESW pumps and their associated piping systems are housed within protective seismic Class I structures supported by the foundation.

The screenhouse is a concrete structure located adjacent to Lake Michigan. Below the superstructure of the building are the pump bays and piers, which guide traveling screens that collect debris and fish. Below the grade on the north and south sides of the screenhouse are discharge tunnels that connect the condensers and discharge piping. Two discharge pipes run out into Lake Michigan. Between the screenhouse and the shore, there is a 20-foot-wide concrete roadway. Below this roadway are the screenhouse forebay and its connection to the de-icing tunnels and intake pipes. The three intake pipes connect the intake cribs, located underwater, to the forebay.

The turbine building is principally reinforced concrete at and below the grade of elevation, consisting mainly of exterior and interior walls, floor slabs, turbine and generator pedestals, and a flat, seismic Class I foundation mat. Above the grade, the turbine building is essentially a steel superstructure covered by aluminum siding.

Within the screenhouse, concrete barriers protect the ESW pumps against turbine missiles and from fires or other accidents in the adjacent ESW pump compartments. In addition, the ESW pump compartments are designed to withstand tornado-velocity wind effects and tornado-borne missiles. Flood protection to Elevation 595' is provided for safety related components. The ESW pump motors are above Elevation 595' and are therefore adequately protected from the maximum flood condition anticipated from a seiche or surge phenomenon.

The intended functions of the turbine building and screenhouse are to support and protect safety related plant equipment. The turbine building and screenhouse provide physical support for themselves and other systems and equipment located within the structures. The walls and roofs of the turbine building and screenhouse protect against tornado-generated or turbine-generated missiles and provide weather protection to the systems and equipment within the structure. The turbine building and screenhouse include nonsafety related commodity groups that must maintain mechanical and structural integrity so that nearby safety related equipment is not adversely affected. The turbine building and screenhouse also support and protect Appendix R to 10 CFR Part 50 safe-shutdown equipment and equipment used to cope with an SBO.

Therefore, the turbine building and screenhouse are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In Table 2.4-3 of the LRA, the applicant identified the steel turbine building and screenhouse component types that are within the scope of license renewal and subject to an AMR, including the AFW pump room doors 226, 227, 228, 229; intake corrugated piping; intake crib framing and plate; miscellaneous steel (catwalks, handrails, ladders, platforms, stairs, and associated supports) in the ESW and AFW pump rooms; miscellaneous steel (ladders and associated supports) in the forebay; screenhouse forebay bar grille and base; sheet piling; and superstructure framing.

The applicant also identified concrete component types, including 12-inch-thick concrete wall; essential motor control center room walls; ESW pump room; AFW pump room (walls, floor, and ceiling); de-icing tunnels; discharge tunnels and bays; foundation mat (turbine building and screenhouse); intake cribs (surrounding sacked concrete); masonry block (4-hour rated); screenhouse below grade walls, beams, and slabs; screenhouse exterior abovegrade walls; and superstructure steel column concrete encasing.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 and CNP UFSAR Section 2.9 to determine whether the applicant identified the turbine building and screenhouse components within the scope of license renewal and subject to AMR. The staff conducted its review in accordance with the guidance described in Section 2.4 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

RAI 2.4-3

The staff's review of the LRA Section 2.4.3 identified one area in which it needed additional information to complete its evaluation of the applicant's scoping and screening results and determine whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The staff requested the following additional information related to the scoping and screening of water-control structures in RAI 2.4-3:

> The staff has reviewed the following information submitted by the applicant, in order to identify all of the structures and components that are essential to ensure access to the ultimate heat sink (Lake Michigan), for safe shutdown following a design basis event:
>
> - LRA Section 2.3.3.2 (Essential Service Water);
> - LRA Section 2.3.3.11 (Screen Wash System);
> - LRA Section 2.4.3 (Turbine Building and Screenhouse);
> - UFSAR Section 9.8.3 (Service Water Systems);
> - UFSAR Section 10.6 (Circulating Water System);
> - UFSAR Figure 1.3-1 (Plot Plan);
> - UFSAR Figure 10.6-1 (Circulating Water System)
>
> As a result of this review, additional information are needed before the staff can reach a conclusion that all essential elements have been included in the LR scope and have been subject to aging management review.

LRA Section 2.4.3, under "Evaluation Boundaries", lists the structural elements that are evaluated for the turbine building and screenhouse. The following elements in the list appear to directly relate to the availability of cooling water for safe shutdown:

- Screenhouse superstructure, which houses the ESW and CW (circulating water) pumps, As well as the traveling screens, stop logs, and bar grills
- Structural components and commodities from, and including, the intake cribs up to but not including the CW pump intake piping
- Structural components and commodities from, and including, the intake cribs up to but not including the ESW pump intake piping
- Structural components and commodities from, and including, the discharge tunnels up to, and including, the discharge jets
- Structural components and commodities that support CW pumps and intake piping
- Structural components and commodities that support ESW pumps and intake piping
- Structural components and commodities associated with the following: Intake cribs; Discharge piping; Forebay; Traveling screens; Trash baskets; Trash collection; Sluice gates; De-icing tunnels; Discharge tunnels; Screenhouse; Piping supports, pump supports, baseplates, and anchors contained within the screenhouse.

However, many of the elements listed above are not specifically identified in LRA Table 2.4-3, "Turbine Building And Screenhouse Components Subject to Aging Management Review", and only two (2) items in the table specify an intended function "SCW" (provide source of cooling water for plant shutdown). These are intake corrugated steel piping and intake crib steel framing and plate. LRA Table 2.4-5, "Structural Commodities Components Subject to Aging Management Review", does not list any components specifically related to the availability of cooling water for safe shutdown.

Therefore, the applicant is requested to:

(a) List all structures and components depicted in UFSAR Figure 10.6-1 (Circulating Water System), and any additional structures and components, that are essential to ensure the availability of cooling water for safe shutdown, up to (but not including) the ESW pumps;

(b) Correlate the list developed in response to (a) above with the structures and components identified in LRA Section 2.4.3 "Evaluation Boundaries";

(c) For each listed structure and component, identify the applicable line item in LRA Table 2.4-3 or LRA Table 2.4-5;

(d) If it is not included in either of these tables, identify where it is addressed in the LRA; and

(e) Identify the applicable AMR reference for each structure and component.

The applicant submitted the following response to RAI 2.4-3, by letter dated May 7, 2004:

> The structures and components that are essential to ensure availability of cooling water for safe shutdown and perform an intended function per 10 CFR 54.4(a) are the de-icing tunnels, discharge tunnels, forebay, intake cribs, intake pipe, screenhouse, and traveling screens. These structures and components are depicted in UFSAR Figure 10.6-1 "Circulating Water System." The structures and components that are not essential to ensure availability of cooling water for safe shutdown include the sluice gates, roller gates, stop log guides, and the discharge elbows.
>
> Correlation of evaluation boundaries in LRA Section 2.4.3 to line items in LRA Table 2.4-3, and to structures and/or components/commodities (*i.e.*, aging management review references) in LRA Table 3.5.2-3 is provided in the table below. All structures and components related to cooling water availability are correlated to line items in the referenced LRA Tables.

Item	**Evaluation Boundaries**	**Line Item in LRA Tables 2.4-3 and 3.5.2-3**
De-icing tunnels	Structural components and commodities that support ESW and CW pumps and intake piping and those associated with the de-icing tunnels	De-icing tunnels
Discharge tunnels	Structural components and commodities from, and including, the discharge tunnels up to, and including, the discharge jets and those associated with the discharge tunnels	Discharge tunnels and bays
Forebay	Screenhouse superstructure which houses the ESW and CW pumps, as well as the traveling screens, stop logs, and bar grilles and those associated with the forebay	Screenhouse forebay bar grille and base

Item	Evaluation Boundaries	Line Item in LRA Tables 2.4-3 and 3.5.2-3
Intake crib	Structural components and commodities that support ESW and CW pumps and intake piping and those associated with the intake cribs	Intake crib framing and plate
Intake crib	Structural components and commodities from, and including, the intake cribs up to but not including the ESW and CW pump intake piping and those associated with the intake cribs	Intake cribs (surrounding sacked concrete)
Intake pipe	Structural components and commodities that support ESW and CW pumps and intake piping	Intake corrugated piping
Screenhouse	Screenhouse superstructure which houses the ESW and CW pumps, as well as the traveling screens, stop logs, and bar grilles	Superstructure framing
Screenhouse	Interior and exterior masonry, including concrete walls and slabs, concrete block walls, concrete pads, and embedded equipment supports	Screenhouse below grade walls, beams, and slabs
Screenhouse	Interior and exterior masonry, including concrete walls and slabs, concrete block walls, concrete pads, and embedded equipment supports	Screenhouse exterior above grade walls
Screenhouse	Interior and exterior masonry, including concrete walls and slabs, concrete block walls, concrete pads, and embedded equipment supports	Table 2.4-3—Foundation mat (turbine building and screenhouse) Table 3.5.2-5— Foundation mat (screenhouse)
Screenhouse	Screenhouse superstructure which houses the ESW and CW pumps, as well as the traveling screens, stop logs, and bar grilles	Superstructure steel column concrete encasing
Traveling screens	Structural components and commodities from, and including, the intake cribs up to but not including the CW pump intake piping and those associated with the traveling screens	Not applicable. The screens move in order to perform their function. Since these components are active, they are not subject to aging management review.

The following provides the staff's evaluation of the applicant's response:

1. UFSAR Section 10.6.2 states: "However in the unlikely event of complete loss of flow to the screen house through the intake pipes adequate flow for essential service water requirements can be provided from the discharge pipes. This is accomplished by opening motor operated sluice gates separating the discharge pipes from the screen house forebay." UFSAR Section 9.8.3.2 also states: "It is inconceivable that damage from barge or ship accidents or even natural phenomena could totally isolate these three pipes; however, motor operated sluice gates which normally separate the discharge from the intake can be opened providing another access to the lake."

   UFSAR Section 10.6.2 also states: "De-icing capability to the intake cribs is provided by shutting off flow in the middle intake pipe to the screen house, by closing its motor operated sluice gate and sending a portion of 'warm' discharge water from either the Unit 1 or Unit 2 discharge tunnel back through the middle pipe to the lake."

   In light of the above information from the UFSAR, the sluice gates, roller gates, discharge piping, and discharge elbows appear to be essential to ensure availability of cooling water for safe shutdown. The response to RAI 2.4-3 specifically states that the sluice gates, roller gates, and discharge elbows are <u>not</u> essential. The applicant needs to explain why the sluice gates, roller gates, and discharge elbows are <u>not</u> essential.

   Discharge piping is not discussed in the RAI response. The applicant needs to address the discharge piping, including the technical basis for determining whether it is or is not essential to ensure availability of cooling water for safe shutdown.

2. The response to RAI 2.4-3 indicates that the traveling screens perform an intended function per 10 CFR 54.4(a). However, for the item "Traveling Screens" in the table, the response states "The screens move in order to perform their function. Since these components are active, they are not subject to aging management review." Are the structural components of the traveling screens subject to periodic inspection for degradation? If so, under what current program? If not, how is performance of intended function ensured?

3. The response to RAI 2.4-3 does not address the trash baskets and trash collection. The applicant needs to address these items, including the technical basis for determining whether they are or are not essential to ensure availability of cooling water for safe shutdown.

4. The response to RAI 2.4-3 does not clearly address the "discharge jets". The applicant needs to describe the physical location and function of the discharge jets, and specifically indicate whether they are essential to ensure availability of cooling water for safe shutdown, and perform an intended function per 10 CFR 54.4(a).

In telephone conference calls with the applicant held on May 17, 2004 and May 21, 2004, the staff described its concerns about the response and requested that the applicant submit additional information to address the SE concerns. The applicant submitted the following supplemental response to RAI 2.4-3, by letter dated August 11, 2004:

The applicant's original response to RAI 2.4-3, provided in the May 7, 2004 RAI response letter, identified the structures and components depicted in UFSAR Figure 10.6-1 (Circulating Water System) that are and are not essential to ensure availability of cooling water for safe shutdown. This supplemental response provides clarification to the original RAI 2.4-3 response by revising and expanding the first paragraph of the original RAI 2.4-3 response to provide the basis for determining the structures and components essential for the flowpath relied upon for safe shutdown. Additionally, the original RAI 2.4-3 response provided a table to correlate the items listed in LRA Section 2.4.3, Evaluation Boundaries, to line items in LRA Tables 2.4-3 and 3.5.2-3. This supplemental response clarifies the correlation for the traveling screen structural supports, which were not specifically addressed in the table in the original RAI response.

The flow path relied on for safe shutdown to ensure the availability of cooling water to the ESW pumps is through the intake pipes to the forebay and screenhouse and then to the ESW pump. The structures and components that are essential for this flow path are the forebay, intake cribs, intake pipes, screenhouse, and traveling screens. The de-icing tunnel and the discharge tunnels are not part of the required flow path but are considered subject to aging management review because they are structurally integral to the screenhouse foundation. These structures and components are depicted in UFSAR Figure 10.6-1. The structures and components that are not essential to ensure availability of cooling water for safe shutdown include the sluice gates, roller gates, stop log guides, discharge elbows, and discharge corrugated piping terminating at the discharge elbows.

The discharge elbows and the discharge corrugated piping terminating at the discharge elbows shown on UFSAR Figure 10.6-1 are not relied on to ensure the availability of cooling water to the ESW pumps. Sluice gates and roller gates can be aligned to supply water to the ESW pumps from the lake through the discharge piping; however, as discussed in UFSAR Section 9.8.3.2, damage from barge or ship accidents or even natural phenomena that could totally isolate these three pipes is not credible. As the maximum demand for the ESW system is a small fraction (approximately one percent) of the total circulating water system demand during normal operation, and the intake pipes would not be totally isolated by a postulated accident or natural phenomenon, the alternative intake flowpath through the discharge piping using the roller gates and sluice gates is not required to ensure the availability of water to the ESW pumps.

The sluice gates and roller gates also provide de-icing capability to the intake cribs. De-icing is accomplished by closing the motor-operated sluice gate to shut off flow to the screenhouse from the middle intake pipe and sending a portion of "warm" discharge water from either the Unit 1 or Unit 2 discharge tunnel back through (via the de-icing tunnel) the middle pipe to the lake. The heated water will recirculate to the other two intake pipes thus keeping the intakes free of ice. De-icing supports normal plant operation and is not credited for emergency operation since warm circulating water flow would not be available with a loss of offsite power. Therefore, sluice gates and roller gates do not perform a license renewal intended function.

> The stop log guides are not safety related and do not perform a license renewal intended function. The purpose of the stop log guides is to hold temporary stop logs in place to allow inspections or maintenance.
>
> As provided in the original RAI 2.4-3 response, the entry in LRA Section 2.4.3, Evaluation Boundaries, applicable to the traveling screens is, "Structural components and commodities from, and including, the intake cribs up to but not including the CW pump intake piping and those associated with the traveling screens." The original response correctly noted that the screens are active components and are not subject to aging management review. This supplemental response clarifies that the structural supports for the screens are part of the screenhouse structure, which is in scope for license renewal and subject to aging management review.

The staff's evaluation of the supplemental response concluded that the applicant still did not adequately address the trash baskets, trash collection, and the "discharge jets." In addition, in the supplemental response that addresses de-icing, the applicant stated the following:

> De-icing supports normal plant operation and is not credited for emergency operation since warm circulating water flow would not be available with a loss of offsite power. Therefore, sluice gates and roller gates do not perform a license renewal intended function.

The staff was not clear which components are relied on during emergency operation to ensure an adequate supply of cooling water for safe shutdown.

In a telephone conference call with the applicant held on November 10, 2004, the staff described its concerns about the supplemental response, and requested that the applicant submit additional information to address the concerns. The applicant submitted the following supplemental response to RAI 2.4-3, by letter dated November 18, 2004:

> In letters dated May 7, 2004, and August 11, 2004, ...I&M provided responses to RAI 2.4-3, regarding the structures and components that are essential to ensure the availability of cooling water for safe shutdown and perform an intended function per 10 CFR 54.4(a). Subsequently, the NRC Staff requested the following information:
>
> - Determine whether the trash baskets and associated trash collection equipment are essential to ensure availability of cooling water for safe shutdown [RAI 2.4-3, Part (3)].
>
> - Describe the physical location and function of the discharge jets and specifically indicate whether they are essential to ensure availability of cooling water for safe shutdown and perform an intended function per 10 CFR 54.4(a) [RAI 2.4-3, Part (4)].
>
> - Identify the components that are relied on for de-icing to ensure an adequate supply of cooling water for safe shutdown, and verify that all of these components are included in the license renewal scope.

Part (3) of the response to RAI 2.4-3 did not address the trash baskets and associated trash collection equipment used for trash collection. Trash collection equipment is used to collect the trash that is removed from the traveling screens by the screen wash system and direct it to the trash baskets. After being filled, the baskets are used to transport the trash for disposal. The trash baskets and associated trash collection equipment are not in the flow path for water entering the screen house and providing suction to the essential service water (ESW) system. Failure of the trash baskets and associated trash collection equipment would not impact the ability to provide water to the ESW system. Therefore, they do not meet the scoping criteria of 10 CFR 54.4.

Part (4) of the response to RAI 2.4-3 did not clearly address the "discharge jets." The discharge jets are at the end of the discharge piping in the lake and act as a diffuser to direct flow away from the intake pipes and distribute the water so as to minimize the environmental effects of the warm water. The discharge jets are located downstream of the discharge corrugated piping and the discharge elbows shown on UFSAR Figure 10.6-1. As discussed in I&M's supplemental response to RAI 2.4-3, included in the August 11, 2004, letter, ...the discharge piping and discharge elbows are not relied upon to ensure the availability of cooling water to the ESW pumps. Therefore, the discharge piping, elbows, and jets do not meet the 10 CFR 54.4 scoping criteria.

The operation of sluice gates and roller gates is needed to establish the flow path for de-icing. De-icing is not credited for emergency operation. Icing is a concern only for the higher flow rates associated with power operation. The concern during power operation is flow restriction caused by ice fouling the traveling screens. The flow restriction can result in the circulating water system being unable to provide the flow necessary to support power operation. During emergency operation, required flow is a small fraction (approximately one percent) of total circulating water capacity. At the significantly lower flow rate required for emergency operation, ice fouling of the traveling screens will not prevent the required flow from reaching the suction of the ESW system pumps. During emergency operation, de-icing is not required to assure the availability of the cooling water supply to the ESW system. The mechanical components credited to ensure an adequate supply of cooling water for safe shutdown during cold weather operation are the ESW pumps, intake piping, strainers, and valves.

The staff finds that the applicant's initial and supplemental responses to RAI 2.4-3 provide an acceptable technical basis to define the water-control SCs that are essential to achieve safe shutdown. In addition, the applicant included these SCs in the license renewal scope. Therefore, the staff's concerns described in RAI 2.4-3 are resolved.

2.4.3.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the turbine building and screenhouse. Therefore, the staff concludes that the applicant adequately identified the SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the turbine building and screenhouse SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Yard Structures

2.4.4.1 Summary of Technical Information in the Application

In Section 2.4.4 of the LRA, the applicant identified the SCs of the yard structures that are subject to an AMR for license renewal. Yard structures are structures at CNP not contained within major buildings, such as the screenhouse, turbine building, auxiliary building, and containment buildings. The yard structures within the scope of license renewal include the following:

- fire protection pump house
- flood protection earth (under roadway)
- gas bottle storage tank rack and foundation
- roadway
- security diesel generator room
- switchyard control house
- tank area pipe tunnel (condensate storage, refueling water storage, and emergency diesel generator piping tunnel)
- tank foundations
  - condensate storage tank
  - fire protection water storage tank
  - primary water storage tank
  - refueling water storage tank
- towers
  - Unit 1 power delivery to switchyard tower
  - Unit 2 power delivery to switchyard tower
- transformer pedestals
- trench from switchyard to startup transformers (duct bank)

Yard structures do not have a specific structural function; rather, they generally support other plant system functions (*i.e.*, FP, containment spray, CCW, and ESW). The yard structures have no unique supports. Section 2.4.5 of the LRA addresses supports with the bulk commodities. Table 2.2-4 of the LRA provides a list of structures not within the scope of license renewal.

In Table 2.4.4-1 of the LRA, the applicant listed the scoping criteria from 10 CFR 54.4 met by each yard structure.

In Table 2.4-4 of the LRA, the applicant identified the steel yard structures component types that are within the scope of license renewal and subject to an AMR, including the FP pump house superstructure, gas bottle storage tank rack, and Tower - Unit 2 power delivery to the switchyard.

The applicant also listed the concrete component types, including FP pump house walls, FP pump house foundation, gas bottle storage tank foundation, roadway, security diesel generator room, switchyard control house, tank area pipe tunnel, tank foundations (refueling water storage), tank foundations (condensate storage), tank foundations (FP water storage), tank foundations (primary water storage), tower (Unit 1 power delivery to switchyard), transformer pedestals (startup), and trench from switchyard to startup transformers (duct bank).

Finally, the applicant listed the earth component types, including the roadway (shoreline).

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 to determine whether the applicant identified the yard structures within the scope of license renewal and subject to AMR. The applicant stated that the CNP UFSAR does not contain structural details of these structures. The staff conducted its review in accordance with the guidance described in Section 2.4 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff found that the applicant included those portions of the yard structures that meet the scoping requirements of 10 CFR 54.4 within the scope of license renewal and identified them as such in LRA Section 2.4.4. Table 2.4-4 of the LRA includes the specific component types that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.4.4.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, and licensing basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the yard structures. Therefore, the staff concludes that the applicant adequately identified the SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.5 Structural Commodities

2.4.5.1 Summary of Technical Information in the Application

In Section 2.4.5 of the LRA, the applicant identified the SCs of the structural commodities that are subject to an AMR for license renewal. Structural commodities are structural members that support or protect system components, mechanical piping, electrical lines, and plant equipment. Structural commodities that are unique to a specific structure are evaluated with that structure. Structural commodities that are common to CNP in-scope systems and structures (*i.e.*, anchors, embedments, equipment supports, instrument panels, racks, cable trays, and conduits) are evaluated as bulk commodities.

In Table 2.4-5 of the LRA, the applicant identified the steel structural commodities component types that are within the scope of license renewal and subject to an AMR, including baseplates; baseplates embedded unistrut; battery racks; blowout panels; cable tray and conduit supports; cable trays and conduits; component supports; cranes, rails, and girders; doors and framing (nonfire-rated); electrical instrument panels and enclosures; fire damper framing (in-wall); fire doors; HVAC duct supports; instrument line supports; instrument racks and frames; miscellaneous embedments; pipe sleeves (mechanical and electrical, not penetrating the containment liner plate); piping supports; roof flashing; stairs, ladders, platforms, and grating (supports); and tube tracks.

The applicant also identified steel (threaded fasteners) component types, including anchor bolts, equipment hatch and personnel access openings threaded fasteners, other threaded fasteners, other threaded fasteners (SFP stainless steel fasteners), and reactor cavity missile block tie-downs.

Concrete component types include cable trays and conduits, flood curbs, hatches, fireproofing, support pedestals, and trenches (pipe and cable).

Elastomer component types include building pressure boundary sealant, cable trays and conduits, divider barrier penetration seals, fire barrier seals, floor plugs, joint elastomer at seismic gaps, penetration seals, roof elastomer, and water stops.

Nonelastomer component types include fire barriers (cable trays).

Finally, other component types include roofing above battery rooms.

2.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5 to determine whether the applicant identified the structural commodities within the scope of license renewal and subject to AMR. The applicant stated that the UFSAR does not contain details of the aging effects or aging management of these commodities. The staff conducted its review in accordance with the guidance described in Section 2.4 of the SRP-LR.

In conducting its review, the staff evaluated the system functions described in the LRA to verify that the applicant did not inadvertently omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that it did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

With one possible exception, the staff found that the applicant included the structural commodities that meet the scoping requirements of 10 CFR 54.4 within the scope of license renewal and identified them as such in LRA Section 2.4.5. Table 2.4-5 of the LRA includes the specific component types that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The exception is thermal insulation that may serve an intended function to limit the temperature of containment concrete to 65 °C (150°F) general and 93 °C (200°F) local during normal operation. The staff requested additional information on this subject as part of RAI 2.4-2. Section 2.4.1.2 of this SER documents the resolution.

2.4.5.3 Conclusion

During its review of the information provided in the LRA, license renewal drawings, licensing basis information, and RAI responses, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the SCs of the structural commodities. Therefore, the staff concludes that the applicant has adequately identified the SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results—Electrical and Instrumentation and Controls Systems

This section addresses the scoping and screening results for electrical and I&C systems at CNP, Units 1 and 2, for license renewal. Pursuant to 10 CFR 54.21(a)(1), an applicant must identify and list SCs subject to an AMR, including 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. This focus allows the staff to confirm that the applicant did not omit any electrical system components that are subject to an AMR. If the review does not identify an omission, the staff has the basis to find that there is reasonable assurance that the applicant identified the electrical system components that are subject to an AMR.

2.5.0 Staff Evaluation Methodology

The staff performed its evaluation of the information provided in the LRA in the same manner for all electrical and I&C systems. The review sought to determine whether the applicant identified the SSCs for a specific electrical or I&C system that appear to meet the scoping criteria specified in the Rule as within the scope of license renewal in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

To perform its evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing its review on components that are not identified as within the scope of renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each electrical and I&C component to determine if the applicant omitted components with intended functions delineated under 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the licensing basis documents to determine whether the LRA specifies all intended functions delineated under 10 CFR 54.4(a). If the staff identified omissions, it requested additional information to resolve the discrepancy.

Once the staff completed its review of the scoping results, it evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether such functions are performed with moving parts or a change in configuration or properties, or whether they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that do not meet either of these criteria, the staff sought to confirm that these electrical and I&C components are subject to an AMR, as required by 10 CFR 54.21(a)(1). If the staff identified discrepancies, it requested additional information to resolve them.

2.5.1 Summary of Technical Information in the Application

The applicant developed a listing of electrical and I&C component commodity groups for systems and structures within the scope of license renewal, as well as active/passive determinations, following the guidance of Appendix B to NEI 95-10. The applicant did not identify any commodity groups beyond those listed in Appendix B to NEI 95-10.

The applicant reviewed these electrical and I&C component commodity groups (determined to be passive) to identify those that are not subject to replacement based on a limited qualified life or specified time period.

Based on its review, the applicant determined that the following electrical and I&C component commodity groups are subject to an AMR:

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- electrical cables used in instrumentation required by the technical specifications for high-voltage, low-current circuits not subject to 10 CFR 50.49 EQ requirements
- inaccessible medium-voltage (4.16 kV to 34.5 kV) cables (*i.e.*, installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements
- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage
- switchyard bus for SBO connections
- high-voltage insulators

All other electrical and I&C component commodity groups are not subject to an AMR because they are (1) active, (2) subject to replacement based on a qualified life or specified time period (long-lived screening), or (3) do not perform any intended functions (scoping).

2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.5 to determine whether there is reasonable assurance that the applicant identified the electrical and I&C systems and 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).

In performing the review, the staff selected system functions described in the UFSAR that are set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of 10 CFR Part 54. The staff also reviewed drawings and focused on components that the applicant did not identify as subject to an AMR to determine whether it omitted any components.

RAI 2.5-3

In a letter dated May 6, 2004, the staff requested clarification on the numbering of the table on page 2.1-17 of the LRA. The paragraph leading to Table 2.1.1 on page 2.1-17 of the LRA refers to Table 2.1-1, which does not exist in the LRA. In response to the staff RAI 2.5-3, by letter dated June 8, 2004, the applicant clarified that, consistent with the labeling convention for other LRA Section 2 tables, the table labeled 2.1.1 on LRA pages 10 and 2.1-17 should have been labeled Table 2.1-1. This editorial explanation is acceptable to the staff. Therefore, the staff's concern described in RAI 2.5-3 is resolved.

RAI 2.5-4

The staff also requested, in RAI 2.5-4, clarification on the statement in LRA Section 2.1.2.3.3 that all electrical penetration assemblies are included in the Environmental Qualification Program and are not subject to AMR. The applicant responded that all of the electrical penetrations, including the penetration assemblies, are safety related and are included in its Environmental Qualification Program, described in LRA Section B.2.1. The staff finds this confirmation acceptable. Therefore, the staff's concern described in RAI 2.5-4 is resolved.

RAI 2.5-5

In RAI 2.5-5, the staff requested additional information on how the applicant will treat nonsafety related cables (not within the scope of license renewal) that share conduits or raceways with in-scope cables included in the AMR. The applicant confirmed that all non-EQ insulated cables installed in structures within the scope of license renewal are included in the scope of license renewal regardless of safety classification. The applicant quoted from LRA Section 2.1.1, which states, "A bounding scoping approach was used for electrical equipment and systems. Electrical and I&C systems as well as Electrical and I&C components in mechanical systems were within the scope of license renewal." The applicant further quoted the following from LRA Section 2.5:

> The basic philosophy for Electrical and I&C component integrated plant assessment (IPA) was that all components were included in the review. Including components beyond those actually required is referred to as an "encompassing" or a "bounding" review. This method eliminates the need for unique identification of each component and its specific location. This method also assured components were not inadvertently excluded from an AMR.

The applicant stated that the commodity group "electrical cables and connections not subject to 10 CFR 50.49 EQ requirements" contains nonsafety related and safety related cables; no cables were eliminated from this commodity type based on intended function. The applicant concluded that, as a part of the bounding approach, it will treat all of these non-EQ insulated cables equally for the license renewal AMR. Based on these confirmations, the staff concludes that the AMR program will include all nonsafety related cables that share conduits or raceways with in-scope cables included in the AMR. Therefore, the staff's concern described in RAI 2.5-5 is resolved.

2.5.3 Conclusion

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

3. AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) contains the Nuclear Regulatory Commission (NRC) staff's evaluation of the applicant's aging management programs (AMPs) and aging management reviews (AMRs). In Appendix B to the license renewal application (LRA), the applicant described the 46 AMPs that it relies on to manage or monitor the aging of long-lived, passive structures and components (SCs). In Section 3 of the LRA, the applicant provided the results of the AMRs for those SCs that it identified in Section 2 of the LRA as within the scope of license renewal and subject to an AMR.

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

In preparing its LRA, Indiana Michigan Power Company (I&M or the applicant) credited NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued July 2001. The GALL Report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining existing programs that are adequate without modification and existing programs that should be augmented for the extended period of operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular SCs for license renewal without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the report.

The GALL Report provides the staff with a summary of NRC-approved AMPs to manage or monitor the aging of SCs 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 also serves as a reference for applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies (1) structures, systems, and components (SSCs), (2) SC materials, (3) the environments to which the SCs are exposed, (4) the aging effects associated with the materials and environments, (5) the AMPs that are credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

To determine whether using the GALL Report 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 (SE) based on this process. The results of the demonstration project confirm that the GALL process will improve the efficiency and effectiveness of the LRA review while maintaining the staff's focus on public health and safety. The staff prepared NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications," (SRP-LR) issued April 2001, based on both the GALL Report model and lessons learned from the demonstration project.

For its review of the LRA for the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, the staff performed audits and reviews during the weeks of December 15, 2003; March 1, 2004; and April 12, 2004, to verify that AMPs and AMR results that the applicant claimed are consistent with the GALL Report are indeed consistent. The staff conducted a public exit meeting on April 15, 2004.

The document titled, "Audit and Review Report for Plant Aging Management Reviews - Donald C. Cook Nuclear Plant, Units 1 and 2," dated September 22, 2004, hereafter referred to as the audit and review report, documents the results and findings of this effort.

3.0.1 Format of the Licence Renewal Application

The applicant submitted an application that followed the standard LRA format, as agreed to between the NRC staff and the Nuclear Energy Institute (NEI) (see letter dated April 7, 2003). This revised LRA format incorporates lessons learned from the staff's reviews of the previous LRAs. These previous applications used a format developed from information gained during an NRC staff and NEI demonstration project conducted to evaluate the use of the GALL Report in the staff's review process.

The organization of Section 3 of the LRA parallels Chapter 3 of the SRP-LR. The following two types of tables present the AMR results information in Section 3 of the LRA:

(1) In Table 1, numbered as Table 3.x.1, "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, and "1" indicates that this is the first table type in Section 3 of the LRA.

(2) In Table 2, numbered as Table 3.x.2-y, "3" indicates the LRA section number, "x" indicates the subsection number of the GALL Report, "2" indicates that this is the second table type in Section 3 of the LRA, and "y" indicates the system table number.

The content of the previous applications and the CNP LRA is essentially the same. In revising the format for the CNP LRA, the applicant intended to modify the tables in Chapter 3 to provide additional information to assist the staff in its review. In Table 1, the applicant summarized the portions of the application it considered to be consistent with the GALL Report. In Table 2, the applicant identified the linkage between the scoping and screening results in Chapter 2 and the AMRs in Chapter 3.

3.0.1.1 Overview of Table 1

Table 3.x.1 (Table 1) provides a summary comparison aligning the facility with the corresponding tables in the GALL Report, Volume 1. The table is essentially the same as Tables 1 through 6 provided in the GALL Report, Volume 1, except that an "Item Number" column replaces the "Type" column and a "Discussion" column replaces the "Item Number in GALL" column. The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1. The applicant used the "Discussion" column to provide clarifying/amplifying information. This column might contain the following types of information:

- further evaluation recommended—information or reference to where that information is located
- the name of a plant-specific program
- exceptions to the GALL Report assumptions
- a discussion of how the line is consistent with the corresponding line item in the GALL Report when that may not be intuitively obvious
- a discussion of how the item is different than the corresponding line item in the GALL Report (*i.e.*, when there is exception taken to an AMP that is listed in the GALL Report)

The format of Table 1 allows the staff to align a specific Table 1 row with the corresponding GALL Report, Volume 1, table row so that consistency can be checked easily.

3.0.1.2 Overview of Table 2

Table 2 provides the detailed results of the AMRs for those components identified in LRA Section 2 as subject to an AMR. The LRA contains a Table 2 for each of the components or systems within a system grouping (*i.e.*, reactor coolant systems (RCSs), engineered safety features (ESFs), auxiliary systems). For example, the ESFs group contains tables specific to the containment spray system, containment isolation system, and emergency core cooling system (ECCS). Table 2 consists of the following nine columns:

(1) The first column, "Component Type," identifies the component types from Section 2 of the LRA that are subject to an AMR and lists them in alphabetical order.

(2) The second column, "Intended Function," contains the license renewal intended functions (including abbreviations where applicable) for the listed component types. The LRA Section 2 intended functions table contains definitions and abbreviations of intended functions.

(3) The third column, "Material," lists the particular materials of construction for the component type.

(4) The fourth column, "Environment," lists the internal and external service environments to which the component types are exposed. The LRA Section 3 internal service environments and external service environments tables provide a list of these environments.

(5) The fifth column lists aging effects requiring management (AERMs). As part of the AMR process, the applicant determined any AERMs for each material and environment combination.

(6) The sixth column, "Aging Management Programs," lists the AMPs the applicant used to manage the identified aging effects.

(7) The seventh column, "GALL Volume 2 Item," lists the GALL Report item(s) that the applicant identified in its LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in Table 2 of the SER to the items in the GALL Report. If there is no corresponding item in the GALL Report, the applicant left the column blank. In this way, the applicant identified the AMR results in the LRA tables that correspond to items in the GALL Report tables.

(8) The eighth column, "Table 1 Item," lists the corresponding summary item number from Table 1. If the applicant identified AMR results in Table 2 that are consistent with the GALL Report, then Table 2 lists the associated Table 3.x.1 line summary item number. If there is no corresponding item in the GALL Report, then column eight is left blank. This allows the information from the two tables to be correlated.

(9) The ninth column, "Notes," lists the corresponding notes that the applicant used to identify the alignment of the information in Table 2 with the information in the GALL Report. An NEI working group developed the notes identified by letters, which will be used in future LRAs. Numbers identify plant-specific notes, which provide additional information concerning the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff evaluated each row in Table 1 by moving from left to right across the table. Since the applicant reproduced the component, aging effect/mechanism, AMPs, and information for which further evaluation is recommended from the SRP-LR, no additional staff review of those columns is required. The staff reviewed information provided by the applicant in the discussion column or other sections of the LRA to determine whether the applicant's AMR results and AMPs are consistent with the AMRs and AMP items in the GALL Report.

The staff conducted the following three types of evaluations of the AMRs and associated AMPs:

(1) For items the applicant stated are consistent with the GALL Report, the staff conducted an audit.

(2) For items the applicant stated are consistent with the GALL Report with exceptions, the staff conducted an audit and review of the item and of the applicant's technical justification for the exceptions.

(3) For other items, the staff conducted a technical review.

3.0.2.1 Review of Aging Management Programs

For those AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted an audit to verify that the applicant's AMPs are, indeed, consistent with the AMPs in the GALL Report. For each AMP that has one or more deviations, the staff evaluated each deviation to determine (1) whether the deviation is acceptable and (2) whether the AMP, as modified, will adequately manage the aging effect(s) for which it was credited.

For AMPs that the GALL Report does not evaluate, the staff performed a full review to determine the adequacy of the AMPs. The staff evaluated the AMPs against the following 10 program elements defined in Appendix A to the SRP-LR:

(1) The Scope of Program element should include the specific structures and components subject to an AMR for license renewal.

(2) The Preventive Actions element should prevent or mitigate aging degradation.

(3) The Parameters Monitored or Inspected element should be linked to the degradation of the particular structure and component intended functions(s).

(4) The Detection of Aging Effects element process should occur before there is a loss of structure and component intended functions(s). This includes aspects such as method or technique (*i.e.*, visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.

(5) The Monitoring and Trending element should provide predictability of the extent of degradation and timely corrective or mitigative actions.

(6) The Acceptance Criteria element, against which the need for corrective action will be evaluated, should ensure that the structure and component intended function(s) are maintained under all current licensing basis (CLB) design conditions during the period of extended operation.

(7) The Corrective Actions element, including root cause determination and the prevention of recurrence, should be timely.

(8) The Confirmation Process element should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) The Administrative Controls element should provide a formal review and approval process.

(10) The Operating Experience element, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the program will adequately manage the effects of aging so that the SC intended function(s) will be maintained during the period of extended operation.

The staff reviewed the applicant's Corrective Action Program and documents its findings in Section 3.0.3 of this SER. The staff's evaluation of the Corrective Action Program includes assessment of the Corrective Actions, Confirmation Process, and Administrative Controls program elements. Consequently, the staff's documentation of its review of AMPs not consistent with the GALL Report AMPs only addresses 7 of the 10 program elements.

The staff reviewed the information concerning the Operating Experience program element for the AMPs that are consistent with GALL Report AMPs and documented its findings in its audit and review report.

The staff reviewed the Updated Final Safety Analysis Report (UFSAR) Supplement for each AMP to determine if it adequately described the program or activity, as required by Title 10, Section 54.21(d), of the *Code of Federal Regulations* (10 CFR 54.21(d)).

3.0.2.2 Review of Aging Management Review Results

Table 2 of the LRA contains information concerning the alignment of the AMRs with the AMRs identified in the GALL Report. For a given AMR in Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular component type within a system. The applicant identified the AMRs that correlate between a combination in Table 2 and a combination in the GALL Report by a referenced item number in the "GALL Volume 2 Item" column. The staff conducted an audit to verify the correlation. When this column is blank, it indicates that the applicant could not locate an appropriate corresponding combination in the GALL Report. The staff conducted a technical review of these combinations that are not consistent with the GALL Report. The next column, "Table 1 Item," provides a reference number that indicates the corresponding row in Table 1.

3.0.2.3 NRC-Approved Precedents

To help facilitate the staff review of the LRA, an applicant may reference NRC-approved precedents to demonstrate that its non-GALL programs correspond to programs that the staff had approved for other plants during its review of previous LRAs. When an applicant elects to provide precedent information, the staff determines whether the material presented in the precedent applies to the applicant's facility, determines whether the plant program is bounded by the conditions for which the NRC evaluated and approved the precedent, and verifies that the plant program contains the program elements (or attributes) of the referenced precedent. In general, if the staff determines that these conditions are satisfied, it will use the information in the precedent to frame and focus its review of the applicant's program.

It is important to note that precedent information is not a part of the LRA; it is supplementary information voluntarily provided by the applicant as a reviewer's aid. The existence of a precedent, in and of itself, is not a sufficient basis to accept the applicant's program. Rather, the precedent facilitates the review of the substance of the matters described in the applicant's program. As such, in its documentation of its reviews of programs that are based on precedents, the precedent information is typically implicit in the evaluation rather than explicit. If the staff determines that a precedent identified by the applicant does not apply to the particular plant program for which it is credited, the staff reviews the program in accordance with the SRP-LR, without consideration of the precedent information. The applicant chose to provide precedent information to support its selection of certain CNP programs. Therefore, some of the staff reviews documented in this SER incorporate precedent information in the manner described above.

3.0.2.4 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and associated AMPs that it reviewed, the staff also evaluated the UFSAR Supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation.

3.0.2.5 Documentation and Documents Reviewed

In performing its work, the staff relied heavily on the CNP LRA, the SRP-LR, and the GALL Report. The staff also examined the applicant's precedent review documents and AMP basis documents (a catalog of the documentation used by the applicant to develop or justify its AMPs) and other applicant documents, including selected implementing procedures, to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs.

The staff's audit and review report documents any discrepancies or issues discovered during the audit and review that required a formal response on the docket. If the staff did not docket or resolve an issue before issuing this report, it prepared a request for additional information (RAI) describing the issue and the information needed to resolve the issue. This SER describes the outcome of any such RAIs. Attachment 3 to the staff's audit and review report lists the RAIs associated with this effort.

Attachment 4 to the staff's audit and review report provides a list of documents reviewed by the staff. During its site visits, the staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

Table 3.0.3-1 presents the AMPs credited by the applicant and described in Appendix B to the LRA. The table indicates the GALL Report program with which the applicant claimed its AMP is consistent (if applicable) and the SSCs that credit the program for managing or monitoring aging. The table also provides the section of the SER that documents the staff's evaluation of the program.

Table 3.0.3-1 CNP's Aging Management Programs

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Existing AMPs				
Bolting and Torquing Activities (B.1.2)	Plant specific	NA	Reactor Vessel, Internals and Reactor Coolant System; Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.2
Boral Surveillance (B.1.3)	Plant specific	NA	Auxiliary Systems	3.0.3.3.3

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Boric Acid Corrosion Prevention (B.1.4)	Consistent with enhancements	XI.M10	Reactor Vessel, Internals and Reactor Coolant System; Engineered Safety Features System; Auxiliary Systems; Structures and Component Supports; Electrical and Instrumentation and Controls	3.0.3.2.1
Bottom-Mounted Instrumentation Thimble Tube Inspection (B.1.5)	Plant specific	NA	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.3.4
Containment Leakage Rate Testing (B.1.8)	Consistent	XI.S4	Engineered Safety Features System; Auxiliary Systems; Structures and Component Supports	3.0.3.1
Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection (B.1.9)	Consistent with exception	XI.M11	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.2.3
Diesel Fuel Monitoring (B.1.10)	Consistent with exceptions	XI.M30	Auxiliary Systems	3.0.3.2.4
Fire Protection (B.1.11.1)	Consistent with exceptions and enhancements	XI.M26	Auxiliary Systems; Structures and Component Supports	3.0.3.2.5
Fire Water System (B.1.11.2)	Consistent with exceptions and enhancements	XI.M27	Auxiliary Systems	3.0.3.2.6
Flow-Accelerated Corrosion (B.1.12)	Consistent	XI.M17	Reactor Vessel, Internals and Reactor Coolant System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.1

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWB, IWC, IWD (B.1.14)	Consistent	XI.M1	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE (B.1.15)	Consistent with exceptions	XI.S1	Structures and Component Supports	3.0.3.2.7
Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWF (B.1.16)	Consistent	XI.S3	Structures and Component Supports	3.0.3.1
Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWL (B.1.17)	Consistent with exceptions	XI.S2	Structures and Component Supports	3.0.3.2.8
Inservice Inspection—ASME Section XI, Augmented Inspections (B.1.18)	Plant specific	NA	Engineered Safety Features System	3.0.3.3.6
Instrument Air Quality (B.1.19)	Plant specific	NA	Auxiliary Systems	3.0.3.3.7
Oil Analysis (B.1.23)	Plant specific	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.8
Pressurizer Examinations (B.1.24)	Plant specific	NA	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.3.9

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Preventive Maintenance (B.1.25)	Plant specific	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.10
Reactor Vessel Integrity (B.1.26)	Consistent with enhancements	XI.M31	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.2.10
Service Water System Reliability (B.1.29)	Consistent with exceptions and enhancements	XI.M20	Engineered Safety Features System; Auxiliary Systems	3.0.3.2.11
Steam Generator Integrity Program (B.1.31)	Consistent	XI.M19	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Structures Monitoring —Structures Monitoring (B.1.32)	Consistent with enhancements	XI.S6	Structures and Component Supports	3.0.3.2.12
Structures Monitoring —Crane Inspection (B.1.33)	Consistent with exceptions and enhancements	XI.M23	Structures and Component Supports	3.0.3.2.13
Structures Monitoring —Divider Barrier Seal Inspection (B.1.34)	Plant specific	NA	Structures and Component Supports	3.0.3.3.11
Structures Monitoring —Ice Basket Inspection (B.1.35)	Plant specific	NA	Structures and Component Supports	3.0.3.3.12
Structures Monitoring —Masonry Wall (B.1.36)	Consistent with enhancement	XI.S5	Structures and Component Supports	3.0.3.2.14
System Testing (B.1.37)	Plant specific	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems; Structures and Component Supports	3.0.3.3.13

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
System Walkdown (B.1.38)	*Plant specific*	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.14
Water Chemistry Control—Primary and Secondary Water Chemistry Control (B.1.40.1)	Consistent with enhancements	XI.M2	Reactor Vessel, Internals and Reactor Coolant System; Engineered Safety Features System; Auxiliary Systems; Structures and Component Supports	3.0.3.2.15
Water Chemistry Control—Closed Cooling Water Chemistry Control (B.1.40.2)	Consistent with exceptions	XI.M21	Reactor Vessel, Internals and Reactor Coolant System; Engineered Safety Features System; Auxiliary Systems; Structures and Component Supports	3.0.3.2.16
Water Chemistry Control—Auxiliary Systems Water Chemistry Control (B.1.40.3)	Plant specific	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.16
Environmental Qualification of Electric Component (B.2.1)	Consistent	X.E1		3.0.3.1
Fatigue Monitoring (B.2.2)	Consistent with exception and enhancements	X.M1		3.0.3.2.17
New AMPs				
Alloy 600 Aging Management (B.1.1)	Plant specific	NA	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.3.1
Buried Piping Inspection (B.1.6)	Consistent with exception	XI.M34	Auxiliary Systems	3.0.3.2.2
Cast Austenitic Stainless Steel Evaluation (B.1.7)	Consistent	XI.M12	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Heat Exchanger Monitoring (B.1.13)	Plant specific	NA	Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.3.5

CNP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Non-EQ Inaccessible Medium-Voltage Cable (B.1.20)	Consistent	XI.E3	Electrical and Instrumentation and Controls	3.0.3.1
Non-EQ Instrumentation Circuits Test Review (B.1.21)	Consistent with exception	XI.E2	Electrical and Instrumentation and Controls	3.0.3.2.9
Non-EQ Insulated Cables and Connections (B.1.22)	Consistent	XI.E1	Electrical and Instrumentation and Controls	3.0.3.1
Reactor Vessel Internals Plates, Forgings, Welds, and Bolting (B.1.27)	Consistent	XI.M16	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Reactor Vessel Internals Cast Austenitic Stainless Steel Components (B.1.28)	Consistent	XI.M13	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Small Bore Piping (B.1.30)	Consistent	XI.M32	Reactor Vessel, Internals and Reactor Coolant System	3.0.3.1
Wall Thinning Monitoring (B.1.39)	Plant specific	NA	Engineered Safety Features System; Steam and Power Conversion Systems	3.0.3.3.15
Water Chemistry Control—Chemistry One-Time Inspection (B.1.41)	Consistent	XI.M32	Reactor Vessel, Internals and Reactor Coolant System; Engineered Safety Features System; Auxiliary Systems; Steam and Power Conversion Systems; Structures and Component Supports	3.0.3.3.17

3.0.3.1 AMPs That Are Consistent with the GALL Report

In Appendix B to the LRA, the applicant indicated that the following AMPs are consistent with the GALL Report:

- Cast Austenitic Stainless Steel Evaluation Program
- Containment Leakage Rate Testing Program
- Flow-Accelerated Corrosion Program
- Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWB, IWC, IWD Program
- Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWF Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Insulated Cables and Connections Program
- Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program
- Reactor Vessel Internals Cast Austenitic Stainless Steel Components Program
- Small Bore Piping Program
- Steam Generator Integrity Program
- Environmental Qualification of Electrical Components Program

During an audit, the staff confirmed the applicant's claim of consistency, with the exception of the Flow-Accelerated Corrosion; Reactor Vessel Internals Plates Forgings, Welds, and Bolting; and Steam Generator Integrity Programs. The staff's audit and review report documents the audit findings and conclusions; this section discusses these three programs. The staff determined that these AMPs are consistent with the AMPs described in the GALL Report, including the associated Operating Experience attribute.

3.0.3.1.1 Flow-Accelerated Corrosion

In Section B.1.12 of Appendix B to the CNP LRA, the applicant states that CNP AMP B1.12, "Flow-Accelerated Corrosion Program," is consistent with GALL AMP XI.M17. The applicant did not identify any exceptions. During the audits and inspections, the staff noted that the CNP Flow-Accelerated Corrosion (FAC) Program is consistent withg the GALL AMP, with an exception. The Monitoring and Trending element of GALL AMP XI.M17 requires that if degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning. However, the CNP FAC Program bases its sample expansion determination on a threshold criteria rather than on predicted thickness. Sample size is increased when inspections detect significant FAC wear resulting in a wall thickness threshold of less than or equal to 60 percent of nominal wall thickness. This is an exception to the GALL Report. In RAI B.1.12-1, the staff requested that CNP provide a description of the FAC Program, as modified by the exception, and provide justification for the exception regarding the criteria for performing additional examinations. This was identified by the staff as Open Item B.1.12-1.

By letter dated January 21, 2005, the CNP provided additional information in response to Open Item B.1.12-1, taking the position that the AMP is consistent with the GALL Report, with an exception..

In the FAC Program description in GALL Section XI.M17, the Monitoring and Trending section states, in part, that, "If degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning." CNP stated that literal implementation of this statement from the GALL description is not practical in many cases. If very little degradation is predicted, measured wall thickness may be less than the predicted thickness even though the calculated life of the affected component may exceed the operating life of the plant. In this case, sample expansion would not be warranted. Therefore, the applicant took an exception to the Monitoring and Trending attribute of GALL, Section XI.M17.

The staff noted that the CNP FAC Program is based on industry guidance in the Electric Power Research Institute (EPRI) report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," dated April 1999, which recommends increasing the sample size when inspections of the sample detect significant FAC wear. In the CNP FAC Program, significant FAC wear is defined as FAC resulting in a wall thickness of less than or equal to 60 percent of nominal wall thickness. Sample expansion is typically required if any component is determined to have a wall thickness of less than or equal to 60 percent of nominal wall thickness (must be greater than the allowed minimum wall thickness). In addition, the staff noted that CNP FAC procedures require that a sample expansion be performed when inspection results indicate that a component has a remaining life less than one operating cycle based on a trending of wall thickness measurements. This covers situations where the minimum wall thickness required may be greater than 60 percent of nominal wall thickness.

The staff found this exception to the GALL Report for sample expansion to be acceptable because literal implementation of the sample expansion criterion is not practical in all cases, particularly when the predicted wall thickness change is small and the change is close to the measurement capabilities. Additionally, the staff finds this exception acceptable since the applicant trends expected wall thinning values and requires that the projected acceptable wall thickness be above a threshold value that is above 60 percent nominal wall thickness and above minimum wall thickness. On the basis of the supplemental information submitted by the applicant, all issues related to Open Item B.1.12-1 are resolved.

3.0.3.1.2 Reactor Vessel Internals Plates, Forgings, Welds, and Bolting

Summary of Technical Information in the Application

The applicant's reactor vessel internals (RVI) program is discussed in LRA Section B.1.27, "Reactor Vessel Internals Plates, Forgings, Welds, and Bolting." The applicant states that this program is new and will be comparable with GALL AMP XI.M16, "PWR Vessel Internals," upon implementation prior to the period of extended operation. This program will supplement the RVI inspections required by ASME Section XI, Subsection IWB. The applicant will participate in industry activities concerning aging on pressurized-water reactor (PWR) RVI components.

Staff Evaluation

Based on the limited information provided in LRA Section B.1.27, the staff could not verify the applicant's consistency with GALL for many of the 10 elements in GALL AMP XI.M16. The LRA did not mention the identification of the most susceptible items, an Attribute 1 concern. Nor does it provide the specific water chemistry guidelines used, an Attribute 2 concern. It did not discuss whether the applicant will employ enhanced visual VT-1 examinations or ultrasonic testing (UT) in inspections for certain selected components and locations, an Attribute 4 concern. As a result, the staff issued RAI B.1.27-1. In its letter dated August 19, 2004, the applicant provided detailed information addressing all 10 elements in GALL AMP XI.M16, which makes the following element-by-element evaluation possible.

Scope of Program. This AMP applies to the RVI stainless steel and nickel-based alloy components, as listed in LRA Table 3.1.2-2, "Reactor Vessel Internals (Westinghouse)":

- core barrel (barrel, flange, outlet nozzle, and fasteners)
- core baffle and former plates
- core baffle and former bolts
- lower core plate and lower support columns
- diffuser plate
- lower support plate and lower core plate support column cap
- secondary core support assembly (energy absorbers)
- clevis insert block and fasteners
- thermal shield
- upper support plate core support structure
- in-core instrumentation support structure

RAI B1.27-2

The program is designed to manage crack initiation and growth due to stress-corrosion cracking (SCC) or irradiation-assisted SCC (IASCC), loss of fracture toughness due to neutron irradiation embrittlement, and distortion (dimensional changes) due to void swelling of these components. Since the applicant participates in the PWR Materials Reliability Project Issues Group (MRP) program for investigating the impacts of aging on PWR RVI and the Westinghouse Owners Group (WOG) program for baffle and former bolting, accomplishing these AMP objectives depends on whether the MRP and WOG programs have similar objectives to the applicant's program. In RAI B1.27-2, the staff requested information to demonstrate that the MRP and WOG programs address all key issues of this AMP (*i.e.*, crack initiation and growth due to SCC or IASCC, loss of fracture toughness due to neutron irradiation embrittlement, and distortion due to void swelling).

The applicant indicated in a letter dated August 19, 2004 that the information presented to the staff by the MRP Reactor Internals Issues Task Group (ITG) on October 23, 2003, includes a summary of activities to address the specific aging effects and associated aging mechanisms listed in RAI B.1.27-2 (*i.e.*, SCC, IASCC, loss of fracture toughness, and void swelling). The staff has verified this information and concluded that the MRP program on RVI covers the aging effects managed by this AMP. In addition to the WOG program for baffle/former bolting, the MRP program tasks also include IASCC and void swelling of baffle/former bolts. Hence, the first part of RAI B.1.27-2 is closed. However, the applicant did not revise its commitment letter regarding this AMP to address the second part of RAI B.1.27-2, in which the staff requested that the applicant commit to submitting the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program for the staff's review and approval three years prior to the period of extended operation. The applicant made such a commitment in its letter dated October 18, 2004 to supplement its commitment letter; therefore, RAI B.1.27-2 is closed. This is Commitment #36, which supersedes Commitment #18, in Appendix A of this SER.

RAI B.1.27-1

Preventive Actions. The applicant stated in the letter dated August 19, 2004 that the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program is a condition monitoring program. However, the Primary and Secondary Water Chemistry Control Program, which will be referred to hereafter as Water Chemistry Control Program, is an effective preventive program to deter SCC and localized corrosion of the stainless steel and nickel-based alloy RVI components. The Water Chemistry Control Program includes periodic monitoring and control of contaminants in accordance with the guidelines in the EPRI document TR-105714, " PWR Primary Water Chemistry Guidelines," issued January 1999. This attribute is consistent with the GALL Report because it specifies TR-105714 under Preventive Actions as the guideline document for the Water Chemistry Program.

Parameters Monitored or Inspected. The applicant stated that this AMP monitors SCC, IASCC, and void swelling through inspections for the RVI components listed above. The monitoring of distortion caused by void swelling is an enhancement because GALL AMP XI.M16 does not mention it. The staff verified that the GALL Report discusses only SCC and IASCC and loss of fracture toughness due to neutron irradiation embrittlement or void swelling; therefore, this attribute is consistent with the GALL Report with an enhancement.

Detection of Aging Effects. The applicant stated that this AMP will use a visual inspection to detect cracking caused by SCC and IASCC and a volumetric inspection of critical locations (to be determined by the on-going MRP program) to assess cracking for baffle bolts. GALL AMP XI.M16 calls for the adoption of enhanced VT-1 inspection for non-bolted components to achieve a 0.0005 inch resolution. The applicant made a final response to RAI B.1.27-1 in its letter dated October 18, 2004:

> The appropriate visual acuity requirements for augmented visual inspection of components, other than baffle bolts, will be based in part on the critical crack size analysis. It is anticipated that augmented visual inspection may require VT-1 or enhanced VT-1 (defined in NUREG-1801, Section XI.M-19, as the ability to achieve a 0.0005-inch resolution). As discussed in LRA Section B.1.27, CNP will adopt appropriate MRP recommendations in the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program....

Since the applicant will adopt appropriate MRP recommendations in the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program, including enhanced VT-1 to achieve a 0.0005-inch resolution should MRP recommend it, part of RAI B.1.27-1 is resolved.

In terms of the inspection for baffle bolts, the applicant indicated in its August 19, 2004 response to RAI B.1.27-1 that it will use volumetric inspection on critical locations of baffle bolts to detect cracking. This is consistent with the current MRP program and consistent with the GALL Report's call for "other demonstrated acceptable inspection methods to detect cracks between the bolt head and the shank" for bolted components. GALL AMP XI.M16 Element 4, "Detection of Aging Effects," does not discuss void swelling. Therefore, monitoring void swelling is an enhancement to this GALL attribute. The staff will review the management of void swelling when the applicant submits its final RVI Program for NRC review and approval 3 years prior to the actual implementation of this program. The NRC has been in dialogue with the MRP regarding the progress of the program on RVI. This attribute is consistent with the GALL Report with an enhancement.

Monitoring and Trending. The GALL Report requires inspection schedules be in accordance with ASME Code, Section XI, Subsection IWB-2400, "Inspection Schedule," and reliable examination methods be used for susceptible components or locations. The applicant's response stated, "Unit 1 will be inspected in the fifth inspection interval while Unit 2 will be inspected in the sixth interval, prior to the last year of the first license renewal period." This proposed augmented inspection schedule is not consistent with the GALL Report because IWB-2400, which the GALL Report recommends for augmented inspections, requires RVI core support structures to be inspected once during each 10-year interval. It is premature to evaluate this exception to the GALL Report now, considering that the MRP program on RVI has not yet established the appropriate inspection methods and frequency of inspection for approval by the NRC. The staff will review this issue when the applicant submits its final RVI Program for NRC review and approval. The MRP program also includes identification of reliable examination methods for susceptible components or locations. When the NRC reviews and approves the final AMP before its implementation, this attribute will be consistent with the GALL Report, consistent with the GALL Report with an enhancement, or consistent with the GALL Report with an exception, depending on the final inspection plan approved by the NRC.

<u>Acceptance Criteria</u>. The applicant's response stated that for the plates, forgings, welds, and bolting (excluding baffle bolts) that will be visually inspected, critical crack size will be determined by analysis prior to inspection; for components susceptible to void swelling, the acceptance criteria will be developed prior to the inspection; and for baffle bolts, since cracking is unacceptable, the critical number of baffle bolts needed to be intact will be determined by analysis. For this attribute, the GALL Report provides guidance for flaw evaluation only, which requires the use of the ASME Code, Section XI flaw evaluation acceptance criteria in IWB-3400 and IWB-3500. Therefore, for critical flaw size determination, the NRC will use the acceptance criteria of IWB-3400 and IWB-3500. For void swelling, the staff will review its acceptance criteria when the applicant submits its final RVI Program for NRC review and approval. For the critical number of intact baffle bolts determination, the MRP program presented to the staff was not detailed enough to include this analysis; however, the staff will review this analysis and its acceptance criteria, plant-specific or MRP, when the applicant submits its final RVI Program for NRC review and approval. The applicant added the following sentence to the UFSAR Supplement to clarify its commitments regarding participation in the EPRI MRP program on RVI, this is Commitment #19 in Appendix A of this SER:

> I&M will participate in industry-wide programs designed by the PWR Materials Reliability Project Reactor Internals Issues Task Group for investigating the impacts of aging on PWR vessel internal components.

In the October 18, 2004 final response, the applicant also clarified that in terms of the augmented inspections for RVI plates, forgings, welds, and bolting, other than baffle bolts, inspection results will be compared with the appropriate acceptance standards of IWB-3400 and IWB-3500. If the acceptance standards of IWB-3400 and IWB-3500 are not applicable to specific RVI components that require augmented inspection, the applicant will use alternate acceptance standards suggested by the MRP. RAI B.1.27-1 is completely resolved. Hence, this attribute is consistent with the GALL Report. When the NRC reviews and approves the acceptance criteria for void swelling and the critical number of intact baffle bolts needed before the implementation of this program, this attribute will be consistent with the GALL Report with enhancements.

<u>Operating Experience</u>. The applicant stated in LRA Section B.1.27 that its Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program is a new program without plant-specific operating experience. As discussed in Information Notice (IN) 84-18, "Stress Corrosion

Cracking in Pressurized Water Reactor Systems," issued 1984, SCC may occur during refueling operation when there are unacceptable levels of contaminants in the boric acid purchased and airborne contaminants over the SFP. GALL AMP XI.M16 mentions cracking in stainless steel baffle former bolts in foreign and U.S. plants. The applicant has recognized this and plans to resolve it through its participation in the MPR program on RVI. This attribute is consistent with the GALL Report.

Conclusion

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 claimed consistency with the GALL Report are consistent with the GALL Report, or consistent with the GALL Report with enhancements. In addition, the staff has reviewed the exceptions to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging 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 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).

3.0.3.1.3 Steam Generator Integrity

Appendix B.1.31, "Steam Generator Integrity," of the LRA presents the applicant's steam generator AMP. The applicant describes the program as an existing CNP program that is based on the NEI 97-06 Steam Generator Program Guidelines, which provide for detecting degradation of tubing and secondary side internals. The applicant stated that the program uses nondestructive examination (NDE) techniques to identify tubes that are defective and require removal or repair according to the Technical Specifications. The applicant also stated that the program is consistent with that described in the GALL Report, Section XI.M19, Steam Generator Tube Integrity.

The staff reviewed the program described in LRA Appendix B.1.31 to determine whether the applicant has demonstrated that the program will adequately manage the applicable aging effects in the CNP steam generators during the period of extended operation as required by 10 CFR 54.21(a)(3).

Summary of Technical Information in the Application

All of the steam generators at CNP have tubes made from thermally treated Alloy 690, which is considered a corrosion-resistant material for this application. According to Appendix B.1.31, the steam generators were replaced in 1988 (Unit 2) and 2000 (Unit 1) based on industry and site-specific operating experience that affected the integrity of the tubes. Along with the tube material selection, several other design improvements were applied to the replacement steam generators. In Unit 1, for example, stainless steel lattice grid assemblies and flat bar restraints support the tubes, the minimum radius of the U-bend section of tubing was increased, and the

U-bend section of each tube was given a stress-relief heat treatment. In Unit 2, the tubes are supported by stainless steel support plates with quatrefoil-shaped holes, a stainless steel flow distribution baffle with octafoil-shaped holes, and stainless steel anti-vibration bars (AVBs) for the U-bend sections. In both units the tubes were hydraulically expanded into the full thickness of the tubesheet to minimize crevice corrosion and cracking. These tubesheet and tube support features help prevent the accumulation of deposits and concentrated chemical environments known to cause degradation of tubes with less corrosion resistance than the Alloy 690 tubes in the CNP steam generators.

Detailed steam generator inspection results were not included in the application. However, the staff formally reviews all steam generator (SG) tube inspection reports submitted according to the plant technical specifications. Although not performed as part of the license renewal process, the NRC uses these reviews to support its evaluation of the LRA. All of the Unit 1 steam generators were inspected in May 2002 during the first refueling outage following replacement. Four tubes (two in SG 11 and one each in SGs 13 and 14) were plugged due to unexplained signal changes in the bobbin coil voltage amplitude at five manufacturing burnish mark indications between cold-leg tube supports. Babcock & Wilcox attributed the signal change to a metallurgical structure change induced by the heat of the first operating cycle. During the subsequent refueling outage in the fall of 2003, an inspection was performed on a sample of tubes in SG 14. No tubes were plugged during the outage. The only tube degradation reported for the Unit 1 steam generators is fan bar wear of one tube in SG 14 (11 percent through wall); no tubes have been plugged as a result.

The tubes in the Unit 2 steam generators have been inspected five times since installation in 1988. Including 1 tube plugged during the pre-operational inspection due to a manufacturing flaw, a total of 15 tubes have been plugged in the four SGs (1 in SG 21, 6 in SG 23, and 4 each in SGs 22 and 24). All of the 14 cases of tube plugging during inservice inspections occurred in 1994 and 1997, and all were the result of mechanical damage, foreign object wear, or tube support plate wear. No tubes were plugged during the 2002 outage.

Staff Evaluation

In LRA Appendix B.1.31, the applicant stated that the Steam Generator Integrity Program is consistent with the GALL AMP XI.M.19 (Steam Generator Tube Integrity), which is credited for managing the aging effects of the steam generator tubes and secondary side internals needed to maintain tube integrity. GALL AMP XI.M19 recommends preventative measures to mitigate degradation phenomena, assessment of degradation mechanisms, inservice inspection of steam generator tubes to detect degradation, evaluation and plugging or repair, and leakage monitoring to maintain the structural and leakage integrity of the pressure boundary.

The applicant stated that the program is also based upon NEI 97-06, which includes an assessment of degradation mechanisms and considers operating experience from similar steam generators to identify degradation mechanisms. For each mechanism, the EPRI guidelines associated with NEI 97-06 define the inspection techniques, measurement uncertainty, and the sampling strategy. The EPRI guidelines (TR-105714 and TR-102134) associated with NEI 97-06 provide criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data. This includes procedures, probe selection, analysis protocols, and reporting criteria. The performance criteria in NEI 97-06 pertain to structural integrity, accident-induced leakage, and operational leakage. A steam generator program, as defined in NEI 97-06, includes guidance on assessment of degradation mechanisms, inspection, tube integrity assessment, maintenance, plugging, repair, leakage monitoring, and procedures for monitoring and controlling secondary-side and primary-side water chemistry. The applicant's Water Chemistry Control Program, based on EPRI's water chemistry guidelines for PWRs, relies on monitoring and control of reactor water chemistry and secondary water chemistry. The staff accepts the use of GALL AMP XI.M.19, NEI 97-06, and EPRI water chemistry guidelines as the proper framework for managing the aging of steam generator tubes and other components that can affect tube integrity.

RAI B.1.31-1

The applicant credited this program, all or in part, for managing the forms of aging other than tube degradation listed below, but no components other than tubes are mentioned in the program. Therefore, by letter dated June 30, 2004, the staff requested in RAI B.1.31-1 that the applicant discuss how the Steam Generator Integrity Program manages aging of components other than tubes. The following examples were cited:

- material loss of carbon steel tube wrappers in treated water
- cracking of carbon steel tube wrappers in treated water
- material loss of stainless steel tube support plates and AVBs in treated water
- cracking of stainless steel tube support plates and AVBs in treated water
- material loss of carbon steel tube support plate stayrods and spacers in treated water
- cracking of carbon steel tube support plate stayrod nuts in treated water
- loss of mechanical closure integrity of tube support plate stayrod nuts in treated water
- material loss of nickel alloy tubes support plate stayrod washers and AVB retaining rings in treated water
- cracking of nickel alloy tubes support plate stayrod washers and AVB retaining rings in treated water
- material loss of carbon steel lattice grid ring arch bars in treated water
- cracking of carbon steel lattice grid ring studs in treated water
- loss of mechanical closure integrity of carbon steel lattice grid ring studs in treated water
- material loss of stainless steel lattice grid bars, U-bend flat bars, and J-tabs in treated water
- cracking of stainless steel lattice grid bars, U-bend flat bars, and J-tabs in treated water

With respect to the scoping aspect of RAI B.1.31-1, the applicant responded, in a letter dated August 19, 2004, that because these components form the steam generator secondary side tube support structure, they are included in GALL AMP XI.M19 under the Parameters Monitored or Inspected element. This element states that the program detects flaws in tubing or the degradation of secondary side internals needed to maintain tube integrity, and that degradation of steam generator internals is evaluated for corrective actions. The applicant noted that Table 3.1.2-5 of the LRA indicates that these components perform the intended function of providing structural and/or functional support for in-scope components (*i.e.*, the steam generator tubes), and are therefore subject to an AMR.

Regarding the aging management aspect of RAI B.1.31-1, the applicant responded that CNP Steam Generator Integrity Program includes secondary side visual inspections of the tubesheet region, the tube support structures, the U-bend region, and the feedwater distribution system to verify the overall structural integrity of the steam generator secondary side internals. These areas are visually inspected for evidence of degraded conditions, including component deformation, material loss (erosion-corrosion, pitting, wear), cracking, foreign object damage, loss of component integrity, and deposit buildup. If foreign objects are found, the Steam Generator Integrity Program also prescribes corrective actions such as: metallurgical testing of the part; categorization of probable causes, origin, and mitigation; and determination of the need to expand inspections. If degraded conditions or foreign objects are found, the condition is documented using the Corrective Action Program and the inspection scope in the area of interest is expanded until the condition is bounded. In its response to RAI 3.1-4 dated August 11, 2004, the applicant indicated that prior to the inspection of steam generator components, a degradation assessment is completed to ensure that the inspections are adequately focused on the expected degradation mechanisms. Visual examination of the secondary side internals is based on the results of this assessment and include degraded conditions such material loss, cracking, and loss of component integrity. In addition, in its follow-up response to RAI 3.1-3 dated October 18, 2004, the applicant stated that the interval for secondary side visual inspections is no more than two operating cycles. The staff finds this response acceptable because industry experience has shown that these actions are effective in managing aging of secondary-side degradation and foreign material that could affect tube integrity.

RAI B.1.31-2

The UFSAR Supplement for the Steam Generator Integrity Program is presented in LRA Appendix A.2.1.34. The supplement discusses the integrity only of tubes and does not refer to NEI 97-06. As discussed above, the Steam Generator Integrity Program is credited with managing aging of other components that could affect tube integrity. Therefore, by letter dated June 30, 2004, the staff requested in RAI B.1.31-2 that the applicant change the UFSAR Supplement to reflect the full scope of the Steam Generator Integrity program and reference the NEI 97-06 Steam Generator Program Guidelines. By letter dated August 19, 2004, the applicant responded that it would revise Section A.2.1.34 revised for clarification as follows:

> "The Steam Generator Integrity Program, ***which is based on guidance provided in NEI 97-06, Steam Generator Program Guidelines,*** uses nondestructive examination techniques to identify tubes that are defective and need to be removed from service or repaired in accordance with the Technical Specifications. ***In addition, the Steam Generator Integrity Program uses visual inspections to manage the effects of aging on secondary side internals needed to maintain steam generator tube integrity.***"
>
> (NOTE: The text added for clarification in response to RAI B.1.31-2 is in ***bold italics.***)

The staff accepts the revised UFSAR Supplement as an adequate summary description of the Steam Generator Integrity Program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>

On the basis of its review of the applicant's program, the staff finds the Steam Generator Integrity Program is consistent with the GALL Report and will effectively manage aging of steam generator tubes and secondary-side components. The staff therefore concludes that the steam generator tubes will perform their intended function according to the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In Appendix A to the LRA, the applicant provided the UFSAR Supplement required by 10 CFR 54.21(d). The applicant will incorporate the information presented in Appendix A into the UFSAR following the issuance of the renewed operating license. The staff reviewed the information in Appendix A and determined that the information in the UFSAR Supplement provides an adequate summary of the program activities with one exception which is addressed by the staff evaluation of the applicant response to RAI 3.6-3 in Section 3.6.2.1.1 of this SER. The staff reviewed the following sections of Appendix A:

- Section A.2.1.7 of the LRA for the Cast Austenitic Stainless Steel Evaluation Program
- Section A.2.1.8 of the LRA for the Containment Leakage Rate Testing Program
- Section A.2.1.15 of the LRA for the Flow-Accelerated Corrosion Program
- Section A.2.1.17 of the LRA for the Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWB, IWC, IWD Program
- Section A.2.1.19 of the LRA for the Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWF Program
- Section A.2.1.23 of the LRA for the Non-EQ Inaccessible Medium-Voltage Cable Program
- Section A.2.1.25 of the LRA for the Non-EQ Insulated Cables and Connections Program
- Section A.2.1.30 of the LRA for the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program
- Section A.2.1.31 of the LRA for the Reactor Vessel Internals Cast Austenitic Stainless Steel Components Program
- Section A.2.1.33 of the LRA for the Small Bore Piping Program
- Section A.2.1.34 of the LRA for the Steam Generator Integrity Program
- Section A.2.2.3 of the LRA for the Environmental Qualification of Electrical Components Program

The staff reviewed these sections and determined that the information in the UFSAR Supplements adequately summarizes the program activities. The staff finds these sections of the UFSAR Supplements sufficient.

On the basis of its audit, the staff finds that those programs for which the applicant claimed consistency with the GALL Report are indeed consistent with the AMPs described in the GALL Report. The audit and review report documents the details of this effort.

The staff concludes that for the AMPs listed above, the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed the associated UFSAR Supplements for these AMPs and concludes that the UFSAR Supplements provide an adequate summary description of the programs, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

In Appendix B to the LRA, the applicant indicated that the following AMPs are/will be consistent with the GALL Report with exceptions and/or enhancements:

- Boric Acid Corrosion Prevention Program
- Buried Piping Inspection Program
- Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program
- Diesel Fuel Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE Program
- Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWL Program
- Non-EQ Instrumentation Circuits Test Review Program
- Reactor Vessel Integrity Program
- Service Water System Reliability Program
- Structures Monitoring—Structures Monitoring Program
- Structures Monitoring—Crane Inspection Program
- Structures Monitoring—Masonry Wall Program
- Water Chemistry Control—Primary and Secondary Water Chemistry Control Program
- Water Chemistry Control—Closed Cooling Water Chemistry Control Program
- Fatigue Monitoring Program

For AMPs that the applicant claimed are consistent with the GALL Report with exceptions or enhancements, the staff performed an audit to verify that those attributes or features of the program for which the applicant claimed consistency with the GALL Report are indeed consistent. Furthermore, the staff reviewed the exceptions or enhancements and its justification to determine whether the AMP, with the exceptions or enhancements, remains adequate to manage the aging effects for which it is credited. The staff documented this effort in its audit and review report. The staff also reviewed the exceptions or enhancements to the GALL Report to determine whether they are acceptable. The following sections document the results of the staff's audit and reviews.

3.0.3.2.1 Boric Acid Corrosion Prevention

<u>Summary of Technical Information In the Application</u>

Section B.1.4, "Boric Acid Corrosion Prevention," of the LRA discusses the applicant's Boric Acid Corrosion Prevention Program. The applicant stated that the program will be consistent with GALL AMP XI.M10, "Boric Acid Corrosion," after the program scope is expanded to address electrical components subject to boric acid leakage. The applicant credited this AMP with managing the aging of carbon steel and LAS SCs or electrical components onto which borated water may leak. The enhancements to this AMP are specified in Commitment #4 in Appendix A of this SER.

The applicant developed and implemented this program to meet Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and to monitor the condition of the RCS pressure boundary components for boric acid leakage. The program identifies ferritic steel components within the RCS that are susceptible to corrosion from boric acid leakage and provides for visual inspection of these components and their adjacent SCs. The applicant reviewed its condition reports (CRs) and determined that most plant operating events involving the Boric Acid Corrosion Prevention Program involved minor leakage that was corrected before component damage occurred. The applicant also reviewed an NRC inspection report which concluded that the CNP program meets the requirements of GL 88-05.

The CNP has experienced heat exchanger flange carbon steel bolt degradation as a result of boric acid corrosion caused by boric acid leakage at bolted joints. The applicant detected the degradation by visual examination and replaced the bolting with stainless steel bolts.

<u>Staff Evaluation</u>

RAI B.1.4-1

The applicant indicated that after widening the program scope to include electrical components, the program will be consistent with the GALL Report. However, since the scope of the program described in LRA Section B.1.4 does not mention any specific systems and their locations, the staff was not sure that this program includes all systems and components, inside and outside the containment, which may be subject to boric acid degradation as leakage sources or as SCs adjacent to leakage sources. Hence, a clarification was sought through RAI B.1.4-1. This RAI also asked the applicant to provide information regarding provisions in Boric Acid Corrosion Program for inspecting, detecting, or monitoring degradation of SCs due to boric acid leakage and provisions for inspecting, detecting, or monitoring boric acid leakage in inaccessible locations and areas covered by external insulation surfaces.

The applicant responded in its letter dated August 19, 2004, that the Boric Acid Corrosion Prevention Program applies to portions of systems and structures, both inside and outside of containment, that are subject to an AMR. LRA Sections 3.1 to 3.6 list these SSCs as the reactor pressure vessel (RPV) and control rod drive mechanism (CRDM) pressure boundary, Class 1 piping, valves, and reactor coolant pump, pressurizer, steam generator, containment spray system, containment isolation system, ECCS, containment equalization/hydrogen skimmer (CEQ) system, chemical and volume control (CVCS), fire protection (FP) system, nonsafety related systems and components affecting safety related systems, containment, auxiliary building, structural commodities such as heating, ventilation, and air conditioning (HVAC) duct supports and instrument line supports, and electrical connectors.

The applicant further stated that on-going boric acid corrosion inspection and evaluation commitments made in support of current operations, including those made in response to GL 88-05, will be carried forward through the period of extended operation. When leakage is detected, the leakage path is followed to identify the source and all affected components along the path, including locations covered by insulation. Since the applicant has clarified the scope of this AMP and provided the information regarding inspecting, detecting, or monitoring degradation of SCs due to boric acid leakage, including areas covered by external insulation surfaces, RAI B.1.4-1 is closed.

RAI B.1.4-2

Operating Experience. With regard to operating experience, the LRA states that the program continues to be improved based on operating experience, and program revisions have incorporated lessons learned from CRs and industry guidance. To ensure that the program has been revised appropriately on a continual basis considering operating experience, especially the Davis-Besse vessel head degradation and the CRDM penetration cracking event, the staff issued RAI B.1.4-2. RAI B.1.4-2 also requested the applicant to discuss the implementation of corrective actions in the program to prevent the recurrence of degradation caused by boric acid leakage, as required by GL 88-05.

The applicant responded as follows in a letter dated August 19, 2004:

> The Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program continues to be improved based upon experience, as evidenced by program improvements that incorporate lessons learned from the Davis-Besse vessel head degradation and the control rod drive mechanism penetration cracking discussed in Bulletins 2001-01, 2002-01, 2002-02, and NRC Order EA-03-009 and its successors.

This response has clarified the scope of this AMP. Although components of the RPV and CRDM pressure boundary are listed in LRA Section 3.1 as within the scope of Boric Acid Corrosion Prevention Program, vessel head degradation and the CRDM penetration cracking, which were directly addressed by 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," Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," and NRC Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactor," and its successors, are outside the scope of this program. The Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program specifically manages vessel head degradation and the CRDM penetration cracking. SER Section 3.0.3.2 contains an evaluation of this program, including issues such as lessons learned from the Davis-Besse vessel head degradation and the CRDM penetration cracking discussed in Bulletins 2001-01, 2002-01, 2002-02, and NRC Order EA-03-009 and its successors.

Bulletin 2002-01 also addresses RCPB integrity in general. On July 29, 2003, the NRC issued Regulatory Issue Summary (RIS) 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity.'" This RIS concludes that licensees were complying with the technical specification requirements on RCS leakage and the ASME Code requirements on visual inspection for leaks during system pressure testing. However, the RIS also points out the weaknesses in the current boric acid corrosion control and ASME Section XI inspection programs and suggests steps for licensees to strengthen their inspection programs to address potential cracking and leakage in material susceptible to primary water stress corrosion cracking (PWSCC). Experience at a number of plants in recent years has shown that components made of Alloy 600/82/182 materials are susceptible to PWSCC. The applicant addressed the PWSCC issue by creating a new plant-specific program Alloy 600 Aging Management Program to manage aging effects of Alloy 600/82/182 and Alloy 690/52/152 materials in RCS components. Section

3.0.3.3 of this SER provides the staff evaluation and acceptance of the Alloy 600 Aging Management Program.

As mentioned above, the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program specifically manags the CRDM penetration (Alloy 600/82/182) cracking. The staff considers the applicant's response to Bulletin 2002-01 appropriate based on the 1990 NRC inspection report, which concluded that the Boric Acid Corrosion Prevention Program meets the guidance in GL 88-05; the RIS on Bulletin 2002-01 responses, which concludes that licensees were complying with the technical specification requirements on RCS leakage and the ASME Code requirements; the applicant's creation of Alloy 600 Aging Management Program, which is designed to manage the aging effects of Alloy 600/82/182 and Alloy 690/52/152 materials in RCS components; and the applicant's improved measures on operations walkdowns following a unit shutdown while RCS temperature and pressure are near normal operating condition.

Other recent NRC generic communications, which are related to the boric acid corrosion of susceptible systems and components, include Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity" and Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors." The responses to these two Bulletins are still under staff review. The applicant stated in its August 19, 2004 response to the RAIs for this LRA that, "[c]onsistent with the first and second principles of license renewal, on-going boric acid corrosion inspection and evaluation commitments made in support of current operations...will be carried forward through the period of extended operation." It will carry forward any changes to the Boric Acid Corrosion Prevention Program resulting from the conclusions of these reviews. Therefore, the first part of RAI B.1.4-2 is closed.

In response to the second part of this RAI, concerning the implementation of corrective actions in the Boric Acid Corrosion Prevention Program, the applicant provided, in addition to the replacement of the corroded heat exchanger flange carbon steel bolts with the stainless steel bolts discussed in LRA Section B.1.4, three more examples of corrective actions. They are (1) the replacement of carbon steel packing studs on valves within the RCPB, (2) the identification of components within the RCS that are susceptible to corrosion damage and the use of suitable corrosion resistant materials or the application of protective coatings/claddings, and (3) the review of training programs and procedures to ensure that adequate guidance is given regarding RCPB leakage and corrosion concerns. Therefore, RAI B.1.4-2 is closed.

Hence, the staff found the applicant's program scope to be acceptable. After expanding the Boric Acid Corrosion Prevention Program scope to include electrical components as listed in LRA Table 3.6.1, "Electrical Components, NUREG-1801 Vol. 1," this AMP will be consistent with the GALL Report. Therefore, the staff determines that the program will provide reasonable assurance that age related degradation will be managed during the period of extended operation.

The staff confirmed the applicant's claim that the Boric Acid Corrosion Prevention Program is consistent with the GALL Report. In addition, the staff determined that the applicant properly applied the GALL program to its facility.

UFSAR Supplement

In Appendix A, Section A.2.1.4, to the LRA, the applicant provided the UFSAR Supplement for the Boric Acid Corrosion Prevention Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that this AMP is consistent with the GALL Report. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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 the applicant has identified and taken, or will take, actions to manage the effects of aging during the period of extended operation on the functionality of SCs subject to this AMR, such that there is reasonable assurance that the applicant will continue to conduct the activities authorized by a renewed license in accordance with the CLB, as required by 10 CFR 54.29(a).

The staff reviewed the operating experience associated with the AMPs that are consistent with the GALL Report as listed above. The staff concluded that the applicant adequately considered operating experience associated with the AMPs.

3.0.3.2.2 Buried Piping Inspection

Summary of Technical Information in the Application

Section B.1.6, "Buried Piping Inspection," of the LRA describes the applicant's Buried Piping Inspection Program. In the LRA, the applicant stated that it will initiate this new program before the period of extended operation. This program will be consistent, with exception, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection." The applicant stated that the Buried Piping Inspection Program will include (1) preventive measures to mitigate corrosion and (2) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel components. The applicant also stated that it will implement preventive measures in accordance with standard industry practice for maintaining external coatings and wrappings. It will inspect buried components when excavating them during maintenance. The implementation and enhancement of the Buried Piping Inspection Program are listed as Commitments #5 and #42 in Appendix A of this SER.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

In Section B.1.6 of Appendix B to the LRA, the applicant stated that the Buried Piping Inspection Program will be consistent with GALL AMP XI.M34 with one exception. The Buried Piping Inspection Program takes exception to the Detection of Aging Effect program element, in that the buried tanks and piping will be inspected only when excavated during maintenance activities, rather than based on periodic inspection with a scheduled inspection frequency as recommended by the GALL Report.

The staff reviewed the applicant's operating experience with excavations. Based on its review, the staff finds that the frequency of excavating buried components for maintenance activities will be sufficient to provide reasonable assurance that the applicant will identify the effects of aging before the loss of intended function. Problems discovered in piping require evaluation and reporting under the plant's Corrective Action Program. Excavating such components solely to perform inspections could pose undue risk of damage to protective coatings. The staff finds this exception to be acceptable.

Operating Experience The applicant stated in the LRA that multiple excavations at the site have provided some plant-specific operating experience, even though the Buried Piping Inspection Program is new. The piping and valves that were uncovered and inspected were of the same material (carbon steel) or a less corrosion-resistant material (*i.e.*, Lake Township water and station drainage piping) than the buried piping and tanks in the scope of this program. The review did not identify catastrophic failures of similar components. Failures of fuel oil tanks and piping have been limited to small leaks resulting from localized corrosion, such as pitting.

The applicant also stated that it expects future inspection results from similar excavations to indicate the condition of fuel oil system components. It will consider industry and plant-specific operating experience in the development of this program, as appropriate.

The staff reviewed the documentation for multiple excavations performed at the site for several maintenance activities, such as repairs to Lake Township water, fire protection, and station drainage piping. These excavations indicate that corrosion has not been a problem. The staff also reviewed the site soil characteristics as presented in the applicant's UFSAR Table 5.2-2 and basis documents. The staff finds that soil acidity values are close to the neutral pH value of 7.0. In addition, the lowest soil resistivity value was 21,000 Ohm-cm, and values as high as 727,000 Ohm-cm have been recorded. These relatively high soil resistivity values mitigate concerns with the corrosion of buried structures.

On the basis of its review of the above operating experience and on discussions with the applicant's technical staff, the staff concludes that the Buried Piping Inspection Program will adequately manage the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.6 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Buried Piping Inspection Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exception to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.3 Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection

Summary of Technical Information in the Application

Section B.1.9 of Appendix B to the LRA discusses the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The applicant stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is an existing program at CNP which manages the cracking of nickel-based alloy reactor vessel head (RVH) penetrations exposed to borated water. According to the applicant, continued implementation of this program will ensure that the pressure boundary function is maintained during the period of extended operation. The applicant stated that it will use the Inservice Inspection – ASME Section XI, Subsection IWB, IWC, and IWD and Water Chemistry Control Programs in conjunction with this program to manage cracking of the RVH penetrations. This program manages primary water stress-corrosion cracking (PWSCC) of high nickel-alloy RVH penetrations. The applicant stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is consistent with GALL AMP XI.M11, with the exception that the Detection of Aging Effects is based on responses to NRC Bulletins 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002, and 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002, instead of GL 97-01, "Degradation of Control Rod Drive Mechanism and Other Vessel Closure Head Penetrations," dated April 1, 1997.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program to determine if the program demonstrates that the effects of aging will be adequately managed so that the intended functions of SCs will be maintained consistent with the CLB for the period of extended operation.

Generic Letter 97-01 provides the staff's original basis for inspecting Alloy 600 RVH penetration nozzles in U.S.PWRs. Between November 2000 and April 2001, subsequent to the issuance of GL 97-01, RCPB leakage was identified from the RVH penetration nozzles of four U.S. PWR-design light-water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These cracks initiated from the outer surface of the nozzle, either in the associated J-groove weld or heat-affected zone, and not from the inside surface of the nozzle, as was assumed in the industry responses to GL 97-01. These cracks penetrated through the nozzles and were initially identified as circumferential cracking in U.S. RVH penetration nozzles. In NRC Bulletin 2001-01, the staff discusses the generic safety significance and impacts of these cracks on RVH penetration nozzles and recommends that enhanced visual examination or volumetric examination methods be used for the inspection of RVH nozzles.

In March 2002, during a refueling outage at the Davis-Besse Nuclear Power Station, the licensee for the plant reported the occurrence of reactor coolant leakage from RVH penetration nozzles. As a result of followup evaluations of the reactor coolant leakage, the licensee reported that the leakage resulted in significant boric-acid-related wastage of the RVH. The wastage affected the entire thickness of the RVH with the exception of the RVH cladding. On March 18, 2002, the NRC issued Bulletin 2002-01 to owners of PWR designs, requesting that the licensees address the impact of the Davis-Besse event on the structural integrity of their RVHs and associated penetration nozzles. On August 9, 2002, the staff issued NRC Bulletin 2002-02 to address additional technical issues resulting from the Davis-Besse event. In NRC Bulletin 2002-02, the staff specifically suggests performing further augmented inspections, more comprehensive than those suggested in NRC Bulletin 2001-01, on RVH penetration nozzles. On February 11, 2003, the staff issued Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," to further define to the licensees the frequency and extent of inspection of the RPV head nozzles. On August 21, 2003, the staff issued NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," to advise licensees that they may need to supplement RPV lower head inspections with additional measures to assure the detection of the RCPB leakage. On February 20, 2004, the staff issued First Revised NRC Order EA-03-009 to modify the inspection requirements for RPV heads at PWRs.

The applicant stated that it developed the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program based on the events that resulted in the reactor vessel closure head at Davis-Besse. The applicant also stated that it will continue to refine the program as the requirements resulting from the event at Davis-Besse evolve.

The staff assessed the program against the 10 AMP elements that are described in the GALL Report. The applicant stated that for those AMPs that are comparable to the programs described in the GALL Report, it presented the program discussion in the following format:

- program description
- GALL Report consistency
- exceptions to the GALL Report
- enhancements
- operating experience
- conclusion

The applicant also stated that the corrective actions, confirmation process, and administrative controls are all common to the AMPs. Therefore, further discussion is not necessary and not included in the description of the individual programs. The staff review included these three elements, and the results are provided below.

Program Description The applicant stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is an existing program at CNP. It is comparable to the program described in GALL AMP XI.M11, "Nickel-Alloy Nozzles and Penetrations." The applicant stated that the program manages cracking of nickel-based alloy RVH penetrations exposed to borated water. This program manages PWSCC of high nickel-alloy RVH penetrations.

The applicant stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is comparable to the program described in the GALL Report, with the exception that the program is based on responses to NRC Bulletins 2002-01 and 2002-02, instead of GL 97-01.

RAI B.1.9.2-1

The program description submitted in the application does not include references to NRC Bulletin 2003-02; NRC Order EA-03-009, dated February 11, 2003; and the First Revised NRC Order EA-03-009, dated February 20, 2004, as part of the CLB for the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. Therefore, in RAI B.1.9.2-1, the staff requested the following action of the applicant:

> Update its Program Description to include reference to NRC Bulletin 2002-01, 2002-02, 2003-02, Order EA-03-009 dated February 11, 2003 and the First Revised NRC Order EA-03-009 dated February 20, 2004.

In its letter dated August 11, 2004, the applicant responded to RAI B.1.9.2-1 which references documentation that describes the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The applicant stated that the issue of RPV head inspections, which the Control Rod Drive Mechanism and Other Vessel Head Inspection Program addresses, is the subject of the First Revised NRC Order EA-03-009 and is an evolving issue under 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." The applicant noted that the obligations to satisfy the First Revised NRC Order EA-03-009 supercede the obligations to satisfy NRC Order EA-03-009 and commitments made in response to NRC Bulletins 2002-01 and 2002-02. The applicant will continue ongoing inspection and evaluation activities to comply with the First Revised NRC Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. The applicant noted that this is consistent with the second principle of license renewal, as discussed in the Statements of Consideration (SOC) for the final rule for 10 CFR Part 54, which states that 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. The applicant also stated that the Alloy 600 Aging Management Program will address the commitments made in response to NRC Bulletin 2003-02 which apply to lower vessel head penetrations (VHPs). Consistent with the second principle of license renewal, the applicant will continue ongoing commitments made in response to NRC Bulletin 2003-02 through the period of extended operation.

The issue raised in NRC Bulletin 2003-02 related to cracking of Alloy 600 welds in lower vessel head penetration nozzles and the issue related to cracking of other reactor coolant pressure boundary nickel alloy components (other than those used in the fabrication of upper vessel head penetration nozzles) are emerging issues that are being investigated by the NRC. The staff is currently evaluating the need to enact requirements related to augmented inspections of nickel alloy components in the reactor coolant pressure boundaries of PWRs and the ability of these inspections to detect cracking in and leakage from these components. These current operating issues raise questions about the capability of these components to perform their intended functions during the current license term. The Commission has recognized that aging issues could arise during the license renewal review that raise questions about the capability of structures or components to perform their intended functions during the current term of operation, 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 of the license renewal review. Therefore, this issue is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

However, since this issue might not be resolved prior to issuance of the renewed operating licenses for CNP, Units 1 and 2, the applicant has committed to two license renewal commitments for the Alloy 600 Aging Management Program to address the need to implement additional augmented inspection requirements for nickel alloy components in the CNP reactor coolant pressure boundaries:

> Commitment #1 - "The Alloy 600 Aging Management Program will be implemented prior to the period of extended operation. This program will manage aging effects of Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the reactor coolant system that are not addressed by other aging management programs. This program will detect primary water stress corrosion cracking prior to the loss of component intended function by using the examination and inspection requirements specified in American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI."

> Commitment #2 - "The Alloy 600 Aging Management Program commitment will also be revised to indicate that an inspection plan will be submitted for staff review and approval 3 years prior to the period of extended operation to determine if the program demonstrates an ability to manage the effects of aging pursuant to 10 CFR 54.21(a)(3)."

The staff's evaluation of the inspection plan, when submitted for review and approval, will include an assessment of whether the current ASME Code requirements and any supplemental augmented inspection requirements that may be enacted by the staff for nickel alloy components are sufficient to ensure aging management under 10 CFR 54.21(a) or whether additional actions will be necessary under 10 CFR 54.21(a). Based on this assessment, the staff concludes that the applicant's obligations to comply with the First Revised NRC Order EA-03-009 and two additional license renewal commitments for the Alloy 600 Aging Management Program will be sufficient to ensure management of cracking in the nickel alloy CRDM penetration nozzles and other upper and lower head penetration nozzle components and associated welds, as required by 10 CFR 54.21(a).

Based upon the applicant's response to RAI B.1.9.2-1, the staff concludes that the applicant's obligation to comply with the First Revised Order EA-03-009 along with the two commitments discussed above ensures the structural integrity of the components during the period of extended operation. Therefore, the staff concludes that RAI B.1.9.2-1is closed.

Preventive Actions The applicant stated in the program description that it uses the Inservice Inspection – ASME Section XI and Water Chemistry Control Programs in conjunction with this program to manage cracking of the RVH penetrations.

RAI B.1.9.2-2

The applicant did not state that material replacement is an available option to prevent or mitigate the potential for PWSCC. Therefore, in RAI B.1.9.2-2, the staff requested the following action of the applicant:

> The applicant is requested to include a preventive action section in its program to include examples of actions taken or to be taken to prevent ARDMs, the types of materials considered for replacement, and also include compliance with the First Revised NRC Order EA-03-009 or successor regulatory requirements.

In its letter dated August 11, 2004, the applicant's response to RAI B.1.9.2-2 stated the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is consistent with, but includes an exception to, the program attributes described in the GALL Report, Section XI.M11. Details of compliance with the GALL Report, Section XI.M11, specifies the following preventive actions:

> Preventive measures to mitigate PWSCC are in accordance with EPRI guidelines in TR-105714. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in NUREG-1801, Chapter XI.M2, Water Chemistry.

The applicant stated the Primary and Secondary Water Chemistry Control Program provides preventive measures to minimize the potential for cracking of nickel-based alloy nozzles. With the inclusion of enhancements, this program, which is described in LRA Section B.1.40.1, will be consistent with the GALL Report, Section XI.M2.

In its response, the applicant stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program is designed to manage the effects of PWSCC. The program does not preclude material replacement as an option to prevent or mitigate PWSCC. When a part is replaced, appropriate materials for the proposed replacement (such as Alloy 690 and 52/152 weld materials) are selected in accordance with good engineering practice.

The applicant stated that it will carry forward its obligations to comply with the First Revised Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. This is consistent with the SOC for the final rule under 10 CFR Part 54.

The staff concludes that the implementation of the applicant's obligation to comply with First Revised Order EA-03-009 referenced in the response to RAI B.1.9.2-2 will ensure that the appropriate changes will be made (i.e., those that assure the structural integrity of the RVH penetrations during the extended period of extended operation). Therefore, the staff considers RAI B.1.9.2-2 closed.

RAI B.1.9.2-3

Parameters Monitored or Inspected The staff reviewed this element and concluded that the applicant must provide additional information. Therefore, in RAI B.1.9.2-3, the staff requested the following actions of the applicant:

> The applicant stated that the program monitors the effects of PWSCC on the intended function of the CRDM and other Alloy 600 head penetrations by detection and sizing of cracks and coolant leakage by ISI. The program needs to state that monitoring will be in accordance with the First Revised Order EA-03-009 dated February 20, 2004 and also identify specifically how cracks will be sized.

In its letter dated August 11, 2004, the applicant responded to RAI B.1.9.2-3 that the site documentation describes the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The issue of RPV head inspections, which the Control Rod Drive Mechanism and Other Vessel Head Inspection Program addresses, is the subject of the First Revised NRC Order EA-03-009 and is an evolving 10 CFR Part 50 issue. References 1 through 5 of the applicant's response to RAI B.1.9.2-1 provide the I&M CLB, which applies to implementation of the requirements of the First Revised NRC Order EA-03-009, including monitoring requirements and flaw characterization. The applicant will continue ongoing inspection and evaluation activities to comply with the First Revised NRC Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. The applicant noted that this is consistent with the second principle of license renewal, as discussed in the SOC for the final rule for 10 CFR Part 54, which states that 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.

The applicant also stated that the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program monitors the cracking of nickel-based alloy nozzles with partial penetration welds in the reactor vessel closure head. The applicant stated that it will continue ongoing monitoring activities to comply with First Revised NRC Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. The applicant stated that this is also consistent with the SOC for the final rule for 10 CFR Part 54.

The staff concludes that the applicant's obligations to comply with the First Revised Order EA-03-009 and successor orders or regulations referenced in the response to RAI B.1.9.2-3 will ensure that the appropriate changes will be implemented (*i.e.*, those that assure the structural integrity of the RVH penetrations during the extended period of extended operation). Therefore, the staff considers RAI B.1.9.2-3 closed.

RAI B.1.9.2-4

Detection of Aging Effects The GALL Report identifies that the scope and schedule of inspections, including the leakage detection system, is based on NRC GL 97-01. The applicant stated that the CNP program is based on responses to NRC Bulletins 2002-01 and 2002-02, instead of NRC GL 97-01. Therefore, in RAI B.1.9.2-4, the staff requested the following action of the applicant:

- Update the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program to reference Bulletin 2002-03; NRC Order EA-03-009, dated February 11, 2003; and the First Revised NRC Order EA-03-009, dated February 20, 2004, as the basis for the scope and schedule of the inspections. In addition, the program must identify any enhanced leakage detection methods used for detecting small leaks during plant operation, as well as programs and models used to assess PWSCC susceptibility for CNP.

In its letter dated August 11, 2004, the applicant responded to RAI B.1.9.2-4 that the site documentation contains details of the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The issue of RPV head inspections, which the Control Rod Drive Mechanism and Other Vessel Head Inspection Program addresses, is the subject of the First Revised NRC Order EA-03-009 and is an evolving 10 CFR Part 50 issue. The applicant stated that References 1 through 5 for its response to RAI B.1.9.2-1 provide the CLB relevant to the implementation of the requirements of the First Revised NRC Order EA-03-009. The applicant will continue ongoing inspection and evaluation activities to comply with the First Revised NRC Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. The applicant noted that this is consistent with the second principle of license renewal, as discussed in the SOC for the final rule for 10 CFR Part 54, which states that 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. The applicant also stated that the CNP technical specifications document the operability requirements for RCS leakage detection systems. The applicant identified the Alloy 600 Aging Management Program as managing the aging effects for bottom-mounted instrumentation (BMI) nozzles. It will continue commitments made in response to Bulletin 2003-02 through the period of extended operation.

The issue raised in NRC Bulletin 2003-02 related to cracking of Alloy 600 welds in lower vessel head penetration nozzles and the issue related to cracking of other reactor coolant pressure boundary nickel alloy components (other than those used in the fabrication of upper vessel head penetration nozzles) are emerging issues that are being investigated by the NRC. The staff is currently evaluating the need to enact requirements related to augmented inspections of nickel alloy components in the reactor coolant pressure boundaries of PWRs and the ability of these inspections to detect cracking in and leakage from these components. These current operating issues raise questions about the capability of these components to perform their intended functions during the current license term. The Commission has recognized that aging issues could arise during the license renewal review that raise questions about the capability of structures or components to perform their intended functions during the current term of operation, 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 of the license renewal review. Therefore, this issue is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

However, since this issue might not be resolved prior to issuance of the renewed operating licenses for D.C Cook, Unit 1 and 2, the applicant has committed to the following two license renewal commitments for the Alloy 600 Aging Management Program to address the need to implement additional augmented inspection requirements for nickel alloy components in the CNP reactor coolant pressure boundaries:

Commitment #1 - "The Alloy 600 Aging Management Program will be implemented prior to the period of extended operation. This program will manage aging effects of Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the reactor coolant system that are not addressed by other aging management programs. This program will detect primary water stress corrosion cracking prior to the loss of component intended function by using the examination and inspection requirements specified in American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI."

Commitment #2 - "The Alloy 600 Aging Management Program commitment will also be revised to indicate that an inspection plan will be submitted for staff review and approval 3 years prior to the period of extended operation to determine if the program demonstrates an ability to manage the effects of aging pursuant to 10 CFR 54.21(a)(3)."

The staff's evaluation of the inspection plan, when submitted for review and approval, will include an assessment of whether the current ASME Code requirements and any supplemental augmented inspection requirements that may be enacted by the staff for nickel alloy components are sufficient to ensure aging management under 10 CFR 54.21(a) or whether additional actions will be necessary under 10 CFR 54.21(a). Based on this assessment, the staff concludes that the applicant's obligations to comply with the First Revised NRC Order EA-03-009 and two additional license renewal commitments for the Alloy 600 Aging Management Program will be sufficient to ensure management of cracking in the nickel alloy CRDM penetration nozzles and other upper and lower head penetration nozzle components and associated welds, as required by 10 CFR 54.21(a).

Based upon the applicant's response to RAI B.1.9.2-4, the staff concludes that the applicant's obligation to comply with the First Revised Order EA-03-009 along with the two commitments discussed above ensures the structural integrity of the components during the period of extended operation. Therefore, the staff concludes that RAI B.1.9.2-4 is closed.

RAI B.1.9.2-5

<u>Monitoring and Trending</u> The GALL Report states that inspection schedules are based on the susceptibility assessments in GL 97-01. Therefore, in RAI B.1.9.2-5, the staff requested the following actions of the applicant:

> Update B.1.9 to include a Monitoring and Trending element. The element should include current inspection schedules and frequency of inspections based on any findings of initial inspections, how inspection results are used to update susceptibility models, and identify models that are used to evaluate crack growth and flaw evaluations.

In its letter dated August 11, 2004, the applicant responded to RAI B.1.9.2-5 that the site documentation contains details of the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The issue of RPV head inspections, which the Control Rod Drive Mechanism and Other Vessel Head Inspection Program addresses, is the subject of the First Revised NRC Order EA-03-009 and is an evolving 10 CFR Part 50 issue. The applicant stated that References 1 through 5 for its response to RAI B.1.9.2-1 provide the CLB relevant to the implementation of the requirements of the First Revised NRC Order EA-03-009, including inspection schedule and frequency requirements. The applicant will continue ongoing inspection and evaluation activities to comply with the First Revised NRC Order EA-03-009 and successor orders and regulations, and order conditions thereto, through the period of extended operation. The applicant noted that this is consistent with the second principle of license renewal, as discussed in the SOC for the final rule for 10 CFR Part 54, which states that 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.

The staff concludes that the applicant's obligations to comply with First Revised Order EA-03-009 and successor orders or regulations referenced in the response to RAI B.1.9.2-5 will ensure that the appropriate changes will be implemented (i.e., those that assure the structural integrity of the RVH penetrations during the extended period of extended operation). Therefore, the staff considers RAI B.1.9.2-5 closed.

RAI B.1.9.2-6.

Acceptance Criteria The GALL Report states that any indication detected must be evaluated in accordance with Section XI of the ASME Code or other acceptable flaw evaluation criteria. To verify the adequacy of the long-term inspection program and acceptance criteria and assess if there have been significant changes since the applicant's response to NRC GL 97-01, the applicant must provide references to appropriate industry model revisions or provide updated information on crack initiation and growth data and models used. Therefore, in RAI B.1.9.2-6, the staff requested the following actions of the applicant:

> Update B.1.9 to include an Acceptance Criteria element and to provide updated information on crack initiation and crack growth data and models used. Additionally, include references to the NRC Bulletins 2002-01, 2002-02, 2003-02, Order EA-03-009 dated February 11, 2003, and the First Revised NRC Order EA-03-009.

In its letter dated August 11, 2004, the applicant responded to RAI B.1.9.2-6 that the site documentation contains details of the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The issue of RPV head inspections, which the Control Rod Drive Mechanism and Other Vessel Head Inspection Program addresses, is the subject of the First Revised NRC Order EA-03-009 and is an evolving 10 CFR Part 50 issue. The applicant stated that References 1 through 5 for its response to RAI B.1.9.2-1 provide its CLB relevant to the implementation of the requirements of the First Revised NRC Order EA-03-009, including acceptance criteria and updated information on crack initiation and growth data and models used. The applicant will continue ongoing inspection and evaluation activities to comply with the First Revised NRC Order EA-03-009 and successor orders or regulations, and order conditions thereto, through the period of extended operation. The applicant stated that this is consistent with the second principle of license renewal, as discussed in the Statements of Consideration for the final rule for 10 CFR Part 54, which states that 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. The applicant also stated that the CNP Alloy 600 Aging Management Program will address commitments made in response to NRC Bulletin 2003-02 which apply to lower VHPs. It will continue ongoing commitments made in response to NRC Bulletin 2003-02 through the period of extended operation.

The issue raised in NRC Bulletin 2003-02 related to cracking of Alloy 600 welds in lower vessel head penetration nozzles and the issue related to cracking of other reactor coolant pressure boundary nickel alloy components (other than those used in the fabrication of upper vessel head penetration nozzles) are emerging issues that are being investigated by the NRC. The staff is currently evaluating the need to enact requirements related to augmented inspections of nickel alloy components in the reactor coolant pressure boundaries of PWRs and the ability of these inspections to detect cracking in and leakage from these components. These current operating issues raise questions about the capability of these components to perform their intended functions during the current license term. The Commission has recognized that aging issues could arise during the license renewal review that raise questions about the capability of structures or components to perform their intended functions during the current term of operation, 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 of the license renewal review. Therefore, this issue is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

However, since this issue might not be resolved prior to issuance of the renewed operating licenses for CNP, Units 1 and 2, the applicant has committed to the following two license renewal commitments for the Alloy 600 Aging Management Program to address the need to implement additional augmented inspection requirements for nickel alloy components in the CNP reactor coolant pressure boundaries:

> Commitment #1 - "The Alloy 600 Aging Management Program will be implemented prior to the period of extended operation. This program will manage aging effects of Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the reactor coolant system that are not addressed by other aging management programs. This program will detect primary water stress corrosion cracking prior to the loss of component intended function by using the examination and inspection requirements specified in American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI."

> Commitment #2 - "The Alloy 600 Aging Management Program commitment will also be revised to indicate that an inspection plan will be submitted for staff review and approval 3 years prior to the period of extended operation to determine if the program demonstrates an ability to manage the effects of aging pursuant to 10 CFR 54.21(a)(3)."

The staff's evaluation of the inspection plan, when submitted for review and approval, will include an assessment of whether the current ASME Code requirements and any supplemental augmented inspection requirements that may be enacted by the staff for nickel alloy components are sufficient to ensure aging management under 10 CFR 54.21(a) or whether additional actions will be necessary under 10 CFR 54.21(a). Based on this assessment, the staff concludes that the applicant's obligations to comply with the First Revised NRC Order EA-03-009 and two additional license renewal commitments for the Alloy 600 Aging Management Program will be sufficient to ensure management of cracking in the nickel alloy

CRDM penetration nozzles and other upper and lower head penetration nozzle components and associated welds, as required by 10 CFR 54.21(a).

Based upon the applicant's response to RAI B.1.9.2-6, the staff concludes that the applicant's obligation to comply with the First Revised Order EA-03-009 along with the two commitments discussed above ensures the structural integrity of the components during the period of extended operation. Therefore, the staff concludes that RAI B.1.9.2-6 is closed.

<u>Corrective Actions</u> The applicant stated that it implements the CNP quality assurance procedures, review and approval process, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The applicant stated that the CNP corrective actions are consistent with the GALL Report. The staff considers this element to be acceptable because it meets the requirements of Appendix B to 10 CFR Part 50 and the GALL Report.

<u>Confirmation Process</u> The applicant stated that it implements CNP procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The applicant also stated that the CNP confirmation process is consistent with the GALL Report. The staff considers this element to be acceptable because it meets the requirements of Appendix B to 10 CFR Part 50 and the GALL Report.

<u>Administrative Controls</u> The applicant stated that it implements the CNP quality assurance procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. In addition, the CNP administrative controls are consistent with the GALL Report. The staff considers this element to be acceptable because it meets the requirements of Appendix B to 10 CFR Part 50 and the GALL Report.

<u>Operating Experience</u> The applicant stated that, to date, it has not detected VHP leakage in either CNP Unit 1 or Unit 2. The applicant stated that, during the Unit 2 Cycle 10 refueling outage completed in 1994, eddy current testing was performed on 71 of the 78 VHPs. One penetration showed closely spaced axial indications. The flaw evaluation results showed that the through-wall acceptance criteria would not be violated for the next 18-month fuel cycle. During the following Unit 2 Cycle 11 refueling outage completed in 1996, reinspection of this penetration identified no significant flaw growth. The applicant stated that it repaired the penetration by embedding the flaw using an alternate repair method approved by the NRC.

The applicant stated that during refueling outages completed on June 9, 2002, for Unit 1, and February 28, 2002, for Unit 2, it performed 100-percent bare-metal visual inspections of the RVHs under the insulation. It also performed either surface examination (eddy current testing or PT) or ultrasonic testing on the CRDM nozzle penetrations. The applicant did not identify any unacceptable flaws or degradation requiring repair in these inspections. The applicant also stated that during the Unit 2 refueling outage completed in June 20, 2003, it identified and repaired small indications on two penetrations and evaluated indications on two other penetrations as not needing repair.

RAI B.1.9.2-7

The Operating Experience element submitted in the application does not include references to inspections and flaw evaluations in accordance with NRC Bulletins 2002-01, 2002-02, and 2003-02, and NRC Order EA-03-009. Therefore, in RAI B.1.9.2-7, the staff requested that the applicant update the Operating Experience element to reference the inspections and flaw evaluations performed that apply to these bulletins and order.

The applicant responded to RAI B.1.9.2-7 in the supplemental letter reply to RAI 1.9.2-1, dated August 11, 2004. Based on the applicant's response, the staff considers RAI B.1.9.2-7 to be closed.

UFSAR Supplement

In Appendix A, Section A.2.1.9, to the LRA, the applicant provided the Updated Final Safety Analysis Report (UFSAR) Supplement for the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program. The staff reviewed this section and verified that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

The staff has reviewed the information provided in Section B.1.9 of Appendix B to the LRA as supplemented by the applicant's responses to the RAIs in its letters dated August 11 and 19, 2004. On the basis of this review, the applicant demonstrated that it will have a program in place, approved by the staff, which demonstrates that the effects of aging associated with CRDM and other vessel head penetrations 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).

3.0.3.2.4 Diesel Fuel Monitoring

Summary of Technical Information in the Application

Section B.1.10, "Diesel Fuel Monitoring," of the LRA describes the applicant's Diesel Fuel Monitoring Program. In the LRA, the applicant stated that this existing program is consistent, with exceptions, with GALL AMP XI.M30, "Fuel Oil Chemistry Program." The applicant further stated that the Diesel Fuel Monitoring Program ensures that adequate diesel fuel quality is maintained to prevent corrosion of the fuel oil systems associated with the emergency diesel generators (EDGs), diesel-driven fire pump, and security diesel.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and its justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In Section B.1.10 of Appendix B to the LRA, the applicant stated that the Diesel Fuel Monitoring Program is consistent with GALL AMP XI.M30 with exceptions. The Diesel Fuel Monitoring Program takes exception to the (1) Scope of Program, Parameters Monitored or Inspected, Detection of Aging Effects, and Corrective Action program elements such that this program does not address, or monitor and sample for microbiologically influenced corrosion (MIC), (2) Preventive Actions program element such that no additives are used beyond what the refiner adds during production, (3) Parameters Monitored/Inspected and Acceptance Criteria program elements such that (a) only American Society for Testing and Materials (ASTM) Standard D 1796, "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method," issued 2002, is used for determination of water and sediment, rather than Standards D 1796 and D 2709 and (b) the applicant specified the method of ASTM Standard D 2276, "Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling," with a 0.8 μm filter, instead of the modified ASTM Standard D 2276, Method A, with a 3 μm filter; (4) Detection of Aging Effects element such that the program does not include ultrasonic measurements of tank bottoms; and (5) Monitoring and trending program element such that the water and particulate contamination and biological activity are not trended.

The applicant stated in the LRA that plant-specific operating experience has not indicated significant problems related to MIC. The applicant attributed the lack of such problems to *minimizing water contamination in the diesel fuel storage tanks.* The applicant also stated that the Diesel Fuel Monitoring Program has effectively managed aging effects. In its 25 years of operating experience, no evidence of microbial degradation of the fuel or MIC-related corrosion to fuel system components has been observed. On the basis of its review of operating experience for the Diesel Fuel Monitoring Program, the staff finds the applicant's exception (*i.e.* not to address or monitor and sample for MIC) to be acceptable.

The applicant also stated in the LRA that the diesel fuel contains a comprehensive additive package provided by the refiner and certified by the supplier that has a higher percentage of a straight-run distillation component (instead of catalytically cracked), which lends greater resistance to fuel degradation by oxidation. Further, the storage system, which maintains the fuel at a nearly constant temperature of 13°C (55 °F), enhances the diesel fuel's long-term stability. Additionally, the applicant stated that, in its 25 years of operating experience, it has not observed any evidence of microbial degradation of the fuel or MIC-related corrosion to fuel system components. On the basis of its review of operating experience for the Diesel Fuel Monitoring Program, the staff finds the applicant's exception (*i.e.*, not to use additives beyond what the refiner adds during production) to be acceptable.

The staff determined that of the three standards recommended by the GALL Report, only the guidance presented in ASTM Standard D 1796 applies to fuel oils with the viscosity of that used at CNP. Therefore, the staff finds the applicant's use of Standard D 1796 for the determination of water and sediment, rather than Standards D 1796 and D 2709, to be acceptable.

The guidance in the GALL Report concerning the use of modified ASTM Standard D 2276, Method A, allows for use of a filter with a larger (3.0 μm) pore size for the detection of particulates. The staff noted that the use of a filter with a smaller (0.8 μm) pore size would not increase the likelihood that aging effects would go undetected and thus potentially affect the ability of components to perform their intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's use of ASTM Standard D 2276 to be acceptable.

The applicant stated in the LRA that it visually inspects for degradation the internal surfaces of tanks that are drained for cleaning. The CNP technical specifications require that EDG fuel oil storage tanks either be drained and cleaned or that their contents undergo a filtering test every 10 years. The staff reviewed recent fuel oil operating experience, which includes an ultrasonic thickness measurement of the tank bottom surface in 1995 and visual tank inspections of both EDG fuel oil storage tanks in 1996 (*i.e.*, draining, cleaning, and inspecting). In 1995, the applicant's results for the ultrasonic measurements indicated that the tank plates were within the manufacturer's tolerance of a new plate. The applicant did not detect any measurable corrosion or observe any corrosion during the visual tank inspections. In addition, the staff determined that the applicant mitigated the introduction of fuel oil contaminants into the tanks, which cause degradation of tank bottoms, through compliance with diesel fuel oil standards and periodic sampling.

The applicant stated in its engineering report that corrosion may occur at locations in which contaminants accumulate, such as the tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring. The staff pointed out that this statement in the applicant's program basis document is inconsistent with the exception taken to perform ultrasonic thickness measurements to check for significant degradation. The applicant responded that it will not perform ultrasonic thickness measurements on the tank bottom surface because of the operating experience described above and the periodic technical specification requirements to drain and clean the tanks or filter test their contents every 10 years.

On the basis of its review of operating experience, the 10 year drain/clean or filter testing inspection requirement in the CNP technical specifications, and the controls provided to minimize introduction of fuel oil contaminants into the tanks, the staff finds that the applicant's exception to the program (*i.e.* to exclude ultrasonic measurements of tank bottoms) to be acceptable.

The applicant stated that its Corrective Action Program provides reasonable assurance that trends of repeated failures to meet acceptance criteria will be identified and addressed with appropriate corrective actions. On the basis of its review of operating experience for the Diesel Fuel Monitoring Program, the staff finds the applicant exception such that the water and particulate contamination and biological activity are not trended to be acceptable.

<u>Operating Experience</u> The applicant stated in the LRA that its review of relevant Crs demonstrates that it has improved this program through evaluation of site and industry operating experience. As an example, it found the procedure that implements technical specification surveillance requirements for sampling diesel fuel to be inadequate in providing explicit instructions for consideration of the dyes that are used to identify the type of the fuel. A CR documented the procedural deficiency and provided a root cause analysis to resolve the issues. Corrective actions were implemented to prevent recurrence.

The applicant stated that the Diesel Fuel Monitoring Program has effectively managed aging effects. In its 25 years of operating experience, the applicant has not observed any evidence of microbial degradation of the fuel or MIC-related corrosion to the fuel system components.

The staff reviewed records of the ultrasonic measurements of wall thickness performed on tanks in 1995. The results indicate that the ultrasonic thickness measurements were within manufacturing tolerances for new material. Because the applicant detected iron oxide sediment in the tanks, it cleaned these tanks in 1996. Based on the observed condition of the tank walls, the applicant attributed the sediment to sources outside the tanks. The applicant used the criteria from ASTM D 4176-82, which specifies "clear and bright appearance" for monitoring particulate contamination of the new fuel before its addition to the storage tanks. The staff noted that the applicant's Corrective Action Program has reported problems with implementing this procedure which were properly eliminated in accordance with their Corrective Action Program.

The staff also reviewed the applicant's engineering report that implements the technical specification requirements. On the basis of corrective actions taken and documentation to the effect that filters remain free of indications of particulate contamination, the staff finds this to be acceptable.

On the basis of its review of the above operating experience and on discussions with the applicant's technical staff, the staff concludes that the applicant's Diesel Fuel Monitoring Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.10 of Appendix A to the LRA, the applicant provided its UFSAR Supplement for the Diesel Fuel Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. By letter dated April 23, 2004, the applicant stated that it revised Appendix A, Section A.2.1.10, to clarify that the program monitors fuel oil quality and contaminant concentrations using ASTM standards specified in the plant technical specifications. The applicant stated that it made this revision for completeness. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exceptions to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.5 Fire Protection

Summary of Technical Information in the Application

Section B.1.11.1, "Fire Protection," of the LRA describes the applicant's Fire Protection Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions and enhancements, with GALL AMP XI.M26, "Fire Protection."

The applicant stated in the LRA that the Fire Protection Program includes a fire barrier inspection and a diesel-driven fire pump inspection. The fire barrier inspection requires (1) periodic visual inspection of fire barrier penetration seals and fire barrier walls, ceilings, and floors, and (2) periodic visual inspection and functional tests of fire-rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The program includes periodic inspection and testing of the halon/carbon dioxide (CO_2) fire suppression system.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.11.1 of Appendix B to the LRA, the applicant stated that the Fire Protection Program will be consistent with GALL AMP XI.M34 with exceptions and enhancements. The Fire Protection Program takes exception to the Parameters Monitored or Inspected and Detection of Aging Effects program elements in that (1) fire doors clearances are inspected when fire doors are physically removed for maintenance or repair or for new installations, not bimonthly as recommended by the GALL Report, (2) function tests of fire doors are performed every 6 months (to verify the operability of automatic hold-open, closing mechanisms, and latches), not daily, weekly, or monthly as recommended by the GALL Report, and (3) visual inspection and functional tests of the halon/CO_2 fire suppression system are performed every 18 months, not every 6 months as recommended by the GALL Report. Consistent with Interim Staff Guidance (ISG)-4, "Fire Protection System Piping," inspections for charging pressure, valve lineups, and automatic mode of operation are not credited for aging management.

In ISG-4, the NRC revised the criteria for the GALL AMP XI.M26 Parameters Monitored or Inspected and the Detection of Aging Effects program elements to no longer require visual inspection or functional testing of fire doors on a specific frequency. Rather, the applicant can establish a plant-specific interval to verify the integrity of door surfaces and for clearances, with plant-specific inspection intervals to be determined by engineering evaluation to detect degradation of the fire doors. The applicant's program meets ISG-4. Therefore, the staff finds this exception to be acceptable.

The Fire Protection Program also takes exception to the Monitoring and Trending program element in that trending for this program is performed via the applicant's Corrective Action Program. The applicant stated that the use of its Corrective Action Program provides reasonable assurance that it will identify trends entailing repeat failures to meet acceptance criteria and address them with appropriate corrective actions. On this basis, the staff finds this exception acceptable.

In addition, the applicant committed in the LRA that it will enhance the Fire Protection Program to ensure that the CO_2 and halon procedures require that conditions that may affect the performance of the system (*i.e.*., corrosion, mechanical damage, or damage to dampers) are observed and degraded conditions are addressed. The applicant will also enhance that procedure to ensure that the diesel fuel supply line is monitored for degradation during performance testing. This is Commitment #7 in Appendix A of this SER. These enhancement will be made to the Parameters Monitored or Inspected, Detection of Aging Effects, Monitoring and Trending, and Acceptance Criteria program elements. The applicant stated in the LRA that it will implement these enhancements before the period of extended operation.

The applicant stated that these enhancements will ensure that material conditions that may affect performance of the halon/CO_2 fire suppression system, such as corrosion, mechanical damage, or damage to dampers, are monitored and are subject to the Corrective Action Program.

On the basis that the applicant will revise and clarify the requirements in its plant procedures to further ensure that aging effects are detected and addressed, the staff finds these enhancements to be acceptable.

Operating Experience The applicant stated in the LRA that its CR review found that minor problems with fire protection equipment have been identified and resolved. It performed self-assessments of the program in 1995 and 2002. These assessments identified no significant aging of fire protection components. This operating experience demonstrates that the Fire Protection Program effectively manages the effects of aging on fire protection equipment. The applicant also stated that this conclusion is corroborated by the findings of a 1998 NRC inspection that fire protection equipment was well maintained.

The applicant further stated that, as a result of its review of the CRs, self-assessments, and NRC inspections, it concluded that implementation of the existing Fire Protection Program maintains fire protection equipment and meets applicable regulatory requirements. Thus, this program manages aging effects on fire protection equipment.

The staff reviewed operating experience for the Fire Protection Program. Trending data did not identify deficiencies to this program. A review of the applicant's self-assessment performed in 2002 confirmed that the review did not identify any significant aging of fire protection components. The NRC conducted a triennial fire protection inspection and documented it in a July 16, 2003, inspection report to the applicant. Based on a review of the latest documentation, the staff concludes that the applicant has identified operating experience for the Fire Protection Program and performed corrective actions, where needed, as a result.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Fire Protection Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Appendix A, Section A.2.1.13, to the LRA, the applicant provided the UFSAR Supplement for the Fire Protection Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are, indeed, consistent with the GALL Report. In addition, the staff has reviewed the exceptions and enhancements to the GALL Report program and finds that the applicant has demonstrated that it will effectively manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.6 Fire Water System

Summary of Technical Information in the Application

Section B.1.11.2, "Fire Water System," of the LRA describes the applicant's Fire Water System Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions and enhancements, with GALL AMP XI.M27, "Fire Water System."

The applicant stated that its Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. In addition, these systems are normally maintained at the required operating pressure and monitored in that leakage resulting in the loss of system pressure is immediately detected and corrective actions initiated.

The applicant also stated that it will inspect a sample of sprinkler heads using the guidance in Section 2.3.3.1 of NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." In part, NFPA 25 states that, "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." NFPA 25 also contains guidance to perform this sampling every 10 years after the initial field service testing.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.11.2 of Appendix B to the LRA, the applicant stated that the Fire Water System Program will be consistent with GALL AMP XI.M27 with exceptions and enhancements. The Fire Water System Program takes exception to the Parameters Monitored or Inspected program element in that the applicant does not implement the commitments in NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989, for the Fire Water System Program, as recommended in the GALL Report.

The applicant stated in the LRA that it verifies that every fire main segment (excluding individual system supplies) is clear of obstruction by performing a full-flow test at least once every 3 years. The NRC's ISG-4 revises the criteria for the GALL AMP XI.M27 Parameters Monitored or Inspected program element so that it no longer recommends the use of GL 89-13 in determining the system's ability to maintain pressure and internal system corrosion conditions. Rather, ISG-4 recommends either periodic flow testing of the fire water system using the guidelines of NFPA 25, Chapter 13, Annexes A and D, at the maximum design flow, or periodic wall thickness evaluations to ensure that the system maintains its intended function. On the basis of the applicant's commitment to test fire water system components in accordance with the applicable NFPA codes and standards, the staff finds that this exception is in accordance with ISG-4 and is, therefore, acceptable. This is Commitment #8 in Appendix A of this SER.

The Fire Water System Program also takes exception to the Detection of Aging Effects program element in that (1) the fire hydrant hose gasket inspections are performed once every 18 months rather than annually as recommended by the GALL Report, and (2) fire hydrant hose hydrostatic tests and fire hydrant flow tests are performed at least once every 3 years rather than annually as recommended by the GALL Report.

The staff finds that the applicant's proposed inspection frequencies,following NFPA guidance, are sufficient to detect aging effects which act over a considerable period of time. On the basis of the applicant's commitment to test fire water system components in accordance with the applicable NFPA 25 guidelines, the staff finds these exceptions to be acceptable.

Lastly, the Fire Water System Program takes exception to the Monitoring and Trending program element in that trending for this program is performed via the applicant's Corrective Action Program. For the program element associated with the exception taken by the applicant, the GALL Report states that results of system performance testing are monitored and trended as specified by the NFPA codes and standards. Degradation identified by internal inspection is evaluated. In the LRA, the applicant stated that use of the Corrective Action Program for Monitoring and Trending system performance provides reasonable assurance that it will identify trends entailing repeat failures to meet acceptance criteria and address them with appropriate corrective actions. The staff reviewed the operating experience associated with the Fire Water System Program. On the basis of this operating experience review and the applicant's commitment to test fire water system components in accordance with the applicable NFPA codes and standards, the staff finds that this exception is acceptable.

The applicant stated in the LRA that it will enhance the Fire Water System Program Scope of Program and Detection of Aging Effects program elements in that a sample of sprinkler heads will be inspected using the guidance of NFPA 25, Section 2.3.3.1. In addition, NFPA 25 contains guidance to repeat this sampling every 10 years after the initial field service testing.

The NRC's ISG-4 revises the criteria for the GALL AMP XI.M27 Detection of Aging Effects program element to recommend sprinkler head inspections before the end of the 50-year sprinkler head service life, and at 10-year intervals thereafter during the extended period of operation, to ensure that signs of degradation are detected in a timely manner. On the basis of the revised GALL Report criteria in ISG-4 and the applicant's commitment to rely upon applicable codes and standards to develop test procedures, the staff finds this enhancement to be acceptable.

The applicant also stated that it will enhance the Scope of Program, Detection of Aging Effects, and Monitoring and Trending program elements for the Fire Water System Program to implement the requirements of ISG-4 pertaining to nonintrusive measurement of pipe wall thickness.

The NRC's ISG-4 revises the criteria for the GALL AMP XI.M27 Scope of Program, Detection of Aging Effects, and Monitoring and Trending program elements to recommend nonintrusive (*i.e.*, volumetric test) examinations of fire system piping to detect signs of internal corrosion as an alternative to disassembly of pipe segments for inspection. According to ISG-4, applicants should perform baseline nonintrusive pipe wall thickness evaluations of the fire protection piping to detect this aging effect before the current license term expires. The staff further recommends, in ISG-4, that applicants perform pipe wall thickness evaluations at plant-specific intervals, determined by postinspection engineering evaluations, during the period of extended operation. On the basis of the revised GALL Report criteria in ISG-4 and the applicant's commitment to rely upon applicable codes and standards to develop test procedures, the staff finds this enhancement to be acceptable.

Operating Experience The applicant stated, in the LRA, that it included the operating experience for the Fire Water System Program with that for the Fire Protection Program because the CNP procedures, self-assessments, and NRC inspections cover both programs as one. The applicant's condition report review found that minor problems with fire protection equipment have been identified and resolved. The applicant performed self-assessments of the program in 1995 and 2002, which did not identify any significant aging of fire protection components. This operating experience demonstrates that the Fire Protection Program effectively manages the effects of aging on fire protection equipment. The applicant also stated that the findings of a 1998 NRC inspection that fire protection equipment was well maintained corroborate this conclusion.

The applicant further stated that, as a result of its review of the CRs, self-assessments, and NRC inspections, it concluded that implementation of the existing Fire Protection Program maintains fire protection equipment and meets applicable regulatory requirements. Thus, this program manages aging effects on fire protection equipment.

The staff reviewed operating experience for the Fire Water System Program. A review of the results of a self-assessment that the applicant performed in 2002 confirmed that it did not identify any significant aging of fire protection components. The NRC held its triennial fire protection inspection and documented it in a July 16, 2003, inspection report. Based on a review of the latest documentation, the staff concludes that operating experience for the Fire Water System Program has been captured and program enhancements have been performed as a result.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Fire Water System Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.14 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Fire Water System Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exceptions and enhancements to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.7 Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE

Summary of Technical Information in the Application

Section B.1.15, "Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE," of the LRA describes the applicant's Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE."

The applicant stated in the LRA that 10 CFR 50.55a specifies the use of the examination requirements in the ASME Code, Section XI, Subsection IWE, for steel liners of concrete containments and other containment components. The applicant has the implemented ASME Code, Section XI, 1992 Edition with the 1992 Addenda, as approved in 10 CFR 50.55a. Subsection IWE and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing required program that is applicable to managing aging for license renewal.

The applicant stated in the LRA that the Subsection IWE program encompasses (1) concrete containment steel liners and their integral attachments, (2) containment hatches and airlocks, (3) seals, gaskets, and moisture barriers, and (4) pressure-retaining bolting. Subsection IWE specifies visual examination (*i.e.*, general visual, VT-3, or VT-1) as the primary ISI method. Limited volumetric examination (ultrasonic thickness measurement) and surface examination (*i.e.*, liquid penetrant) may also be necessary in some instances. Subsection IWE specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In Section B.1.15 of Appendix B to the LRA, the applicant stated that the Inservice Inspection—ASME Section XI, Subsection IWE Program will be consistent with GALL AMP XI.S1 with exceptions. The Inservice Inspection—ASME Section XI, Subsection IWE Program takes exception to the Scope of Program and Parameters Monitored or Inspected program elements in that it does not (1) examine Category E-D seals and gaskets and (2) include the Category E-G bolt torque or tension test. For the program elements associated with the exceptions taken by the applicant, the GALL Report states that the components within the scope of Subsection IWE are Class MC pressure-retaining components and their integral attachments, metallic shell and penetration liners of Class CC containments and their integral attachments, containment seals and gaskets, containment pressure-retaining bolting, and metal containment surface areas. In addition, Table IWE-2500-1 specifies that Category E-D seals and gaskets will undergo visual examination (VT-3); Category E-G pressure-retaining bolts will undergo visual examination (VT-1) as well as bolt torque or tension tests.

In the LRA, the applicant cited approved relief requests that allow for verifying the pressure-retaining capability of seals and gaskets by 10 CFR Part 50, Appendix J, Type B leakage testing. The applicant stated that it performs Appendix J Type B leakage testing at least once each inspection interval. The applicant's approved relief requests also include the following alternate provisions to ensure the structural integrity and the leak-tightness of Class MC pressure-retaining bolting:

- Exposed surfaces of bolted connections will be visually examined in accordance with requirements of Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting, Item E8.10.

- Bolted connections will meet the pressure test requirements of Table IWE-2500-1 Examination Category E-P, All Pressure Retaining Components, Item E9.40.

The staff reviewed the relief requests and finds that they provide alternative methods for ensuring that the pressure boundary and structural integrity functions are maintained. Thus, it is not necessary to perform additional tests in accordance with the GALL Report recommendations. On this basis, the staff finds these exceptions to be acceptable.

The Inservice Inspection—ASME Section XI, Subsection IWE Program also takes exception to the Monitoring and Trending program element, in that successive examinations required by IWE-2420(b) and IWE-2430(c) are limited to Class MC components accepted by evaluation in accordance with IWE-3122.4, excluding successive examination of repaired components. For the program element associated with the exception taken by the applicant, the GALL Report states that when component examination results require evaluation of flaws, areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs must be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

In its LRA, the applicant cited an approved relief request that limits the successive examinations required by IWE-2420(b) and IWE-2430(c)) to Class MC components accepted by evaluation in accordance with IWE-3122.4. This limitation excludes successive examination of repaired components. The staff reviewed the relief request and, on that basis, finds this exception to be acceptable.

Operating Experience The applicant stated in the LRA that it performed a self-assessment of Subsection IWE and IWL programs in the fall of 1999, when these programs and their respective implementing documents were under development. The review concluded that the Subsection IWE and IWL programs would be effective structural monitoring programs.

The applicant also stated that operating experience, as documented in CRs and licensee event reports (LERs), indicates that the program effectively monitors containment liner conditions and prescribes appropriate actions when problems are found. For example, the applicant found a hole in the Unit 2 containment liner during the IWE general visual examination. This hole, which went undetected until the first IWE examination, resulted from an inadequate repair of a hole erroneously drilled through the liner during original construction. As another example, the applicant identified liner corrosion when it removed the concrete floor-to-liner joint seal. This area of the liner plate is normally inaccessible and exempt from IWE examination requirements. However, the applicant revised the IWE program to add examinations of this area.

The staff reviewed the operating experience associated with the Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE Program, including the applicant's 1999 self-assessment. Several CRs and two LERs were generated as a result of the self-assessment and other inspections. The applicant revised the IWE program as a result of the identified conditions and corrective actions. The staff confirmed this revision and, on this basis, finds this program to be acceptable.

Based on its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.18 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Inservice Inspection—ASME Section XI, Inservice Inspection, Subsection IWE Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exceptions to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.8 Inservice Inspection—ASME Section XI, Subsection IWL

Summary of Technical Information in the Application

Section B.1.17, "Inservice Inspection—ASME Section XI, Subsection IWL," of the LRA describes the applicant's Inservice Inspection—ASME Section XI, Subsection IWL Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions, with GALL AMP XI.S2, "ASME Section XI, Subsection IWL."

Title 10, Section 50.55a, of the *Code of Federal Regulations* (10 CFR 50.55a) specifies the use of the examination requirements in the ASME Code, Section XI, Subsection IWL, for reinforced concrete containments (Class CC). The applicant has implemented the ASME Code, Section XI, 1992 Edition with the 1992 Addenda, as approved in 10 CFR 50.55a. Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing required program that is applicable to managing aging for license renewal.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report document staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In Section B.1.17 of Appendix B to the LRA, the applicant stated that the Inservice Inspection—ASME Section XI, Subsection IWL Program will be consistent with GALL AMP XI.S2 with exceptions. The Inservice Inspection—ASME Section XI, Subsection IWL Program takes exception to the Scope of Program, Parameters Monitored or Inspected, Monitoring and Trending, and Acceptance Criteria program elements, in that posttensioning systems would not be within the scope of this program. The applicant stated in the LRA that it does not have a posttensioning system. The staff agrees with the applicant, and on this basis the staff finds this exception to be acceptable.

The Inservice Inspection—ASME Section XI, Subsection IWL Program also takes exception to the Detection of Aging Effects program element, in that the maximum direct examination distance specified for remote visual examinations may be extended and the minimum illumination requirements specified may be decreased, provided the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination. For the program element associated with the exception taken by the applicant, the GALL Report states that the frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Subsection IWL requires the performance of ISIs for concrete and unbonded posttensioning systems at 1, 3, and 5 years following the structural integrity test. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments.

The applicant stated in the LRA that an approved relief request includes alternate provisions related to the remote performance of the visual examinations required in accordance with IWL-2510. Specifically, the maximum direct examination distance specified in Table IWA-2210-1 may be extended and the minimum illumination requirements specified in Table IWA-2210-1 may be decreased, provided that the conditions or indications for which the examination is performed can be detected at the chosen distance and illumination. On the basis of the approved relief request, the staff finds this exception to be acceptable.

<u>Operating Experience</u> The applicant stated in the LRA that it performed a self-assessment of the Subsection IWE and IWL programs in the fall of 1999, when the programs and their respective implementing documents were under development. The review concluded that the Subsection IWE and IWL programs would be effective structural monitoring programs.

The applicant also stated that operating experience for the Subsection IWL program, although limited, indicates that this program effectively monitors containment concrete condition and prescribes appropriate actions when problems are found. Program inspections have identified only minor problems. A Subsection IWL ISI conducted in 2001 revealed several surface discrepant conditions in the form of buried wood, exposed rebar, and plastic. Based on the evaluation of the conditions, the applicant concluded that the containment structural integrity was unaffected. The applicant further stated that the program will continue to trend these areas at inspection interval frequencies sufficient to discover degradation well in advance of any impact on the structural integrity of the containment structure.

The staff reviewed the operating experience for the Inservice Inspection—ASME Section XI, Subsection IWL Program, including the results of the inspection conducted in 2001. The staff agrees with the applicant that the presence of foreign material or exposed reinforcing bar does not affect the containment structural integrity.

On the basis of its review of the above operating experience and on discussions with the applicant's technical staff, the staff concludes that the Inservice Inspection—ASME Section XI, Subsection IWL Program adequately manages the aging effects that have been observed at the applicant's plant.

<u>UFSAR Supplement</u>

In Section A.2.1.20 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Inservice Inspection—ASME Section XI, Subsection IWL Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

<u>Conclusion</u>

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are, indeed, consistent with the GALL Report. In addition, the staff has reviewed the exceptions to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.9 Non-EQ Instrumentation Circuits Test Review

Summary of Technical Information in the Application

Section B.1.21, "Non-EQ Instrumentation Circuits Test Review," of the LRA describes the applicant's Non-EQ Instrumentation Circuits Test Review Program. In the LRA, the applicant stated that this new program will be consistent with, but include an exception to, GALL AMP XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

The applicant stated in the LRA that this program provides reasonable assurance that the intended functions of specified electrical cables not subject to environmental qualification (EQ) will be maintained consistent with the CLB through the period of extended operation. The electrical cables included in the scope of this program (1) are not subject to the EQ requirements of 10 CFR 50.49, (2) are used in instrumentation circuits with sensitive, high-voltage, low-level signals, and (3) are exposed to adverse localized environments caused by heat, radiation, or moisture. An adverse localized environment is one that is significantly more severe than the specified service environment for the cable.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

In Section B.1.21of Appendix B to the LRA, the applicant stated that the Non-EQ Instrumentation Circuits Test Review Program will be consistent with GALL AMP XI.E2, with an exception. The Non-EQ Instrumentation Circuits Test Review Program takes exception to the Detection of Aging Effects program element in that it will perform the first reviews before the period of extended operation and every 10 years thereafter, rather than perform the reviews at the normal calibration frequency specified in the technical specifications. The applicant will review calibrations or surveillances that fail to meet the acceptance criteria at the time of the calibration or surveillance. For the program element associated with the exception taken by the applicant, the GALL Report states that the normal calibration frequency specified in the plant technical specifications provides reasonable assurance that severe aging degradation will be detected before the loss of the cable intended function. The first tests for license renewal must be completed before the period of extended operation. In addition, calibration provides sufficient indication of the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria related to instrumentation loop performance.

In discussions with the staff during the audit, the applicant further clarified its position regarding inspection frequency by stating that it intends to closely match the guidance that will be provided in ISG-15, "Revision to Generic Aging Lessons Learned Aging Management Program (AMP) XI.E2," when the guidance is released for final use.

By letter dated May 6, 2004, the staff forwarded an RAI to the applicant that requested confirmation that the applicant intends to be consistent with the proposed ISG-15 in its management of non-EQ cables sensitive to a reduction in insulation resistance. This SER addresses this issue in the staff evaluation of the applicant response to RAI 3.6-2 in Section 3.6.2.1 under the "Staff RAIs Pertaining to Recent Operating Experience and Emerging Issues" subsection.

Operating Experience The applicant stated in the LRA that it will initiate the program before the period of extended operation; therefore, there is no operating experience. As appropriate, the applicant will consider industry and plant-specific operating experience in the development of this program.

The staff finds this acceptable in that the normal inspection process provides reasonable assurance that the applicant will review operating experience in the future to provide objective evidence to support the conclusion that the effects of aging will be managed adequately.

On the basis of its review and discussions with the applicant's technical staff, the staff concludes that the Non-EQ Instrumentation Circuits Test Review Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.24 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Non-EQ Instrumentation Circuits Test Review Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient.

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are, indeed, consistent with the GALL Report. In addition, the staff has reviewed the exception to the GALL Report and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.10 Reactor Vessel Integrity

Summary of Technical Information in the Application

Section B.1.26, "Reactor Vessel Integrity," of the LRA discusses the applicant's Reactor Vessel Surveillance Program. The applicant stated that the program is consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance."

Staff Evaluation

In LRA Section B.1.26, the applicant described its AMP to manage aging in reactor vessel beltline materials. The LRA stated that this AMP will be consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," with the inclusion of two improvements:

(1) the testing of one additional capsule for each unit between 32 effective full-power years (EFPYs) and 48 EFPYs to address the peak fluence expected at 60 years

(2) the adjustment of surveillance data and assessment of impact on embrittlement to address changes in neutron energy spectrum or operating temperature

For this AMP, the GALL Report recommends further evaluation regarding the proposed surveillance capsule withdrawal schedule. The staff reviewed LRA Section B.1.26 to determine whether the applicant properly applied the GALL program to its facility. The staff also reviewed the applicant's evaluation to determine whether the AMP addressed the issue regarding an acceptable reactor vessel surveillance program.

RAI B.1.26-1

Section B.1.26 of the LRA indicates that the applicant will withdraw and test a capsule from each unit, Capsule W for Unit 1 and Capsule S for Unit 2, at approximately 32 EFPYs. Between 32 and 48 EFPYs, it will withdraw and test an additional capsule from each unit with a neutron fluence approximately equivalent to the peak reactor vessel fluence at 48 EFPYs. According to the current capsule withdrawal schedule, documented in WCAP-12483, Revision 1, "Analysis of Capsule U from the American Electric Power Company D.C. Cook Unit 1 Reactor Vessel Radiation Surveillance Program," Capsule W for Unit 1 has already reached a neutron fluence equivalent to 32 EFPYs and Capsule S for Unit 2 will reach a neutron fluence of 1.983×10^{19} neutron per square centimeter (n/cm^2) ($E \geq 1$ million electron volts (MeV)) at the time of withdrawal. Considering that Capsule W for Unit 1 was formerly located at the 4-degree position and known as Capsule S, and Capsule S for Unit 1 was formerly known as Capsule W, in RAI B.1.26-1, the staff requested that the applicant confirm that the LRA reported the most recent information regarding capsule identification. The staff also asked the applicant to provide the projected fluence in n/cm2 and in EFPYs relative to the fluence at the peak RPV fluence location for Capsule W for Unit 1 and Capsule S for Unit 2 at the proposed time of their withdrawal (between 32 and 48 EFPYs).

The applicant responded in its letter dated August 19, 2004, that the Unit 1 capsule identification was wrong and provided the following replacement for the LRA Section B.1.26 table entry regarding the proposed improvement for Monitoring and Trending program element:

> I&M will pull and test one additional standby capsule for each unit between 32 EFPY and 48 EFPY to address the peak fluence expected at 60 years. A fluence update will be performed at approximately 32 EFPY when Capsule S in each unit is pulled and tested. A subsequent fluence update will be performed when the standby capsules are pulled and tested between 32 EFPY and 48 EFPY.

The applicant further reported that the projected fluence and removal time for Unit 1 Capsule S are estimated as 2.018×10^{19} n/cm^2 and 32 EFPY, and for Unit 2 Capsule S, 1.983×10^{19} n/cm^2 and 32 EFPY. The applicant has corrected a mistake in the Unit 1 capsule identification and has provided the fluence information requested by the staff regarding the capsules to be withdrawn at 32 EFPY. The staff considers the response satisfactory and RAI B.1.26-1 is resolved. The proposed improvement cited above and another enhancement regarding actions to be taken due to modifications to design and operation are specified in Commitment #17 in Appendix A of this SER.

Appendix H to 10 CFR Part 50 specifies surveillance program criteria for 40 years of operation. GALL AMP XI.M31 specifies additional criteria for 60 years of operation. The staff determined that compliance with Appendix H criteria regarding capsule design, location, specimens, test procedures, and reporting remain appropriate for the applicant's Reactor Vessel Integrity Program because these items, which satisfy Appendix H now, will stay the same throughout the extended period of operation. To ensure that all capsules in the reactor vessel that will be removed and tested during the period of extended operation still meet the test procedures and reporting requirements of ASTM E 185-82, the staff imposed conditions, as stated at the end of this discussion, to address this specific concern. The discussion below, regarding GALL's consideration of eight items for an acceptable Reactor Vessel Surveillance Program (RVSP) for 60 years of operation, addresses the Appendix H capsule withdrawal schedule during the extended period of operation.

Items 1 to 3 and Item 8 relate to the monitoring of the RPV embrittlement for upper-shelf energy (USE) and pressure temperature (P-T) limits for 60 years in accordance with Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The staff determined that the CNP LRA has satisfied these considerations based on the evaluations and conclusions of SER Section 4.2.1 on Charpy USE and SER Section 4.2.3 on P-T limits.

Item 4 relates to the disposition of pulled and tested capsules for possible future reconstitution use. Item 6 suggests that all other standby capsules exceeding the equivalent RPV fluence of 60 years be removed and placed in storage. LRA Section B.1.26 did not provide this information. The staff requested clarification in RAI B.1.26-2.

RAI B.1.26-2

In response to RAI B.1.26-2, in a letter dated October 18, 2004 the applicant stated the following:

> ...[c]onsistent with NUREG-1801, Section XI.M31, Item 4, I&M will place all capsules that are pulled and tested after August 31, 2000, in storage.
>
> Because the lead factors for the remaining standby capsules are slightly above 1.0, I&M plans to keep the remaining standby capsules in the vessel should I&M decide to pursue

a second license renewal term (*i.e..*, operation to 80 years). As required by 10 CFR 50, Appendix H, I&M will comply with American Society for Testing Materials (ASTM) E 185-82, Table 1, which requires that the standby capsules fluence not be less than once or greater than twice the peak end-of-life vessel fluence.

The staff accepts this response even though it appears that the applicant's decision to keep the remaining standby capsules in the vessel to maintain the standby capsules fluence at a level not less than once or greater than twice the peak end-of-life vessel fluence is not consistent with the GALL example regarding Item 6, which suggests that all other standby capsules exceeding the equivalent RPV fluence of 60 years be removed and placed in storage. The staff's determination is based on the observations that (1) the GALL example does not interpret the Item 6 philosophy properly, which seeks to avoid a situation where further exposure would not provide meaningful metallurgical data and (2) the applicant's approach is in accordance with ASTM E 185-82. Although ASTM E 185-82 applies only to the current period of operation, this specific requirement regarding the standby capsules fluence limit remains valid technically for the extended period of operation. Based on the above, the staff has determined that RAI B.1.26-2 is closed.

Items 5 through 7 in GALL AMP XI.M31 provide recommendations for the withdrawal of capsules during the period of license renewal. The staff has determined that, with the inclusion of the first improvement, the applicant's AMP meets Item 5 in GALL AMP XI.M31, which recommends that at least one capsule should remain in the RPV for testing during the period of extended operation. The withdrawal schedule for this capsule shall be provided for NRC review as specified in the NRC license condition for approving this AMP. With the inclusion of the second improvement, this AMP meets Item 6 in GALL AMP XI.M31 regarding possible future changes to the RPV exposure conditions (*e.g.* neutron flux, spectrum, irradiation temperature). However, the staff noticed that Item 6 also requires that all other standby capsules exceeding the equivalent RPV fluence of 60 years be removed and placed in storage. Consequently, the staff needs the projected dates for all standby capsules (Capsule V and Z for Unit 1 and Capsules V, W, and Z for Unit 2) to reach the fluence equivalent to 60 years of RPV fluence, as well as the plan to remove and store these standby capsules. This concern is addressed in RAI B.1.26-2. Item 7 does not apply to this AMP because this item relates only to applicants without in-vessel capsules. The applicant has multiple standby capsules for both units, and some standby capsules will be in the RPV throughout the period of extended operation for fluence information valuable to the CNP RPVs beyond the period of extended operation.

<u>UFSAR Supplement</u>

The staff also reviewed the applicant's UFSAR Supplement for this AMP. This UFSAR Supplement provides a general description of the Reactor Vessel Surveillance Programs for CNP, Units 1 and 2. Appendix H to 10 CFR Part 50 requires licensees to submit any proposed changes to their Reactor Vessel Surveillance Program withdrawal schedules to the NRC for review and approval. To ensure that this reporting requirement will carry forward after renewal of the the CNP operating licenses, the staff will impose the following license condition in the renewed licenses for CNP, Units 1 and 2, that requires the applicant to submit future changes to the RVSP withdrawal schedules for NRC review and approval:

All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion.

With this license condition, the summary description of the program, as required by 10 CFR 54.21(d), is adequate. Therefore, the staff concludes that the applicant has identified actions that it has taken or will take to manage the effects of aging during the period of extended operation on the functionality of SCs subject to this 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).

Conclusion

On the basis of its review and audit of the applicant's AMP, the staff finds that it is consistent with the GALL Program. In addition, the staff has reviewed the improvements to the plant's existing surveillance program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.2.11 Service Water System Reliability

Summary of Technical Information in the Application

Section B.1.29, "Service Water System Reliability," of the LRA describes the applicant's Service Water Reliability Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions and enhancements, with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The applicant stated in the LRA that the Service Water System Reliability Program relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the essential service water (ESW) system will be managed for the period of extended operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the ESW system, or SCs serviced by the ESW system.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.29 of Appendix B to the LRA, the applicant stated that the Service Water System Reliability Program will be consistent with GALL AMP XI.M20 with exceptions and enhancements. The Service Water System Reliability Program takes exception to the Scope of Program element in that the heat exchangers may receive a thorough visual inspection and cleaning in lieu of thermal performance testing. For the program element associated with the exception taken by the applicant, the GALL Report states that the guidelines of GL 89-13 include a test program to verify heat transfer capabilities. The staff reviewed the applicant's response to GL 89-13 and determined that the applicant's use of visual inspection and cleaning of the heat exchangers in lieu of heat transfer capability testing to ensure that the system can perform its intended function is consistent with that which was accepted by staff in the applicant's GL 89-13 program to manage heat exchangers. Because the staff considers the GL 89-13 program to be an acceptable basis for satisfying its expectations for GL 89-13, and because it is consistent with the CLB, the staff finds this exception to be acceptable.

The Service Water System Reliability Program also takes exception to the Preventive Actions program element in that the components within the scope of this program are lined or coated only as deemed necessary to protect underlying surfaces (*i.e.*, they are not all lined or coated). For the program element associated with the exception taken by the applicant, the GALL Report states that the system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from exposure to aggressive cooling water environments. The staff finds the applicant exception acceptable because the applicant has conducted various inspections of components over time and either upgraded the material of the component such that no coating is required, or coated the components requiring lining or coating.

Further, the Service Water System Reliability Program takes exception to the Monitoring and Trending program element in that inspections and testing are set to commence during refueling outages. For the program element associated with the exception taken by the applicant, the GALL Report states that the inspection scope, method, and testing frequencies are in accordance with the utility commitments under GL 89-13. The applicant performs testing and inspections every refueling outage. The staff determined that the applicant's inspection frequencies are in accordance with the its commitments under GL 89-13; therefore, the staff finds exception to be acceptable.

The applicant stated in the LRA that it will enhance the Service Water System Reliability Program Detection of Aging Effects program element as follows:

- The program will check for evidence of selective leaching during visual inspection.

- The applicant will develop a new preventive maintenance activity, or revise an existing activity, to ensure that the 8-inch expansion joints in the ESW supply lines to the EDG heat exchangers are inspected for evidence of loss of material, change in material properties, and cracking.

RAI 3.3.2-2

The staff finds that visual inspections might not be an adequate preventive and control method for the detection of selective leaching in all systems where it is likely to occur. GALL AMP XI.M33, "Selective Leaching of Material," recommends a visual inspection and a hardness measurement of selected components to determine whether the loss of material from selective leaching is occurring. By letter dated May 6, 2004, the staff forwarded to the applicant RAI 3.3.2-2 that asked it to justify the exclusion of a hardness measurement from the Service Water System Reliability Program to detect selective leaching. By letter dated June 8, 2004, the applicant stated that:

> Since the detection of selective leaching is an enhancement to the Service Water System Reliability Program, specific details on the methods for detection of selective leaching are not available at this time. Implicit in the current commitment to enhance the Service Water System Reliability Program is implementation using industry best practices at the time of implementation. Current industry practices include visual inspections and either hardness testing, as stated in NUREG-1801, Section XI.M33, or other inspection methods. Additionally, in the future, more effective techniques for the detection of selective leaching may become available.

Based on its review, the staff finds the applicant's response to RAI 3.3.2-2 acceptable. The applicant committed to enhance the Service Water System Reliability Program using the best industry practices at the time of implementation for the detection of selective leaching. Therefore, the staff's concern described in RAI 3.3.2-2 is resolved. The enhancement of the Service Water System Reliability Program is specified in Commitment #21 in Appendix A of this SER.

The staff determined that the addition of the inspections of 8-inch expansion joints in the ESW supply lines to the EDG heat exchangers is consistent with the GALL Report. On this basis, the staff finds the second portion of the enhancement to this program element acceptable.

RAI B.1.29-1

In its response to RAI 3.3.2-2, the applicant stated that implicit in the original commitment stated in the LRA to enhance the Service Water System Reliability Program is implementation using the best industry practices at the time of implementation for the detection of selective leaching. To be consistent with the GALL Report, hardness testing or other acceptable physical test is recommended. The commitment did not indicate that the check for selective leaching done during visual inspection will include hardness testing or equivalent physical testing as recommended by the GALL Report. By letter dated February 17, 2005, the staff forwarded to the applicant RAI B.1.29-1 asking it to clearly state if hardness testing, or an acceptable equivalent, will be part of the program. If not, identify the exception being taken to the GALL Report and the basis for that exception. By letter dated March 24, 2005, the applicant include the following commitment:

> I&M will enhance the Service Water System Reliability Program to manage loss of material due to selective leaching of susceptible materials by visual inspections and hardness testing or an equivalent physical test.

This is Commitment #41 in Appendix A of this SER. Based on its review, the staff finds the applicant's response to RAI B.1.29-1 acceptable. Therefore, the staff's concern described in RAI B.1.29-1 is resolved.

<u>Operating Experience</u> The applicant stated in the LRA that its review of operating experience for the Service Water System Reliability Program included CRs, program health reports, procedure revisions, and LERs. It established this program to meet the requirements of GL 89-13, which includes recommendations based on extensive industry operating experience. Examples of aging effects noted in a report prepared by the applicant in 2002 include minor galvanic or crevice corrosion of the component cooling water (CCW) heat exchanger tubesheets, identified by inspection and cracking of tube seam welds, and MIC pitting of the

containment spray heat exchangers, identified by eddy current testing. The identification of these effects demonstrates that program activities effectively detect minor degradation before it becomes significant.

The applicant further stated that inspections and tests performed in accordance with the Service Water System Reliability Program have effectively identified degradation such as aging effects that could impact the capabilities of the ESW system. When the applicant identifies deficiencies, it performs the appropriate corrective actions. The combination of inspections and testing is adequate to ensure that the aging effects from the exposure to ESW are adequately managed for this system.

The staff reviewed correspondence and reports associated with the applicant's response to GL 89-13 and subsequent activities related to the ESW system. In addition to industry experience, the applicant has experienced significant challenges to the ESW system. The staff reviewed a CR related to a fish kill and observed that the applicant's actions went beyond those components directly affected by the event, leading to both the enhancement of its program to address GL 89-13 and the discovery of numerous latent problems similar to those that are managed by this program. The staff reviewed the applicant's document related to this program and finds that an appropriate level of attention to plant-specific operating experience is evident.

On the basis of its review and discussions with the applicant's technical staff, the staff concludes that the Service Water System Reliability Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.32 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Service Water System Reliability Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its audit and review of the applicant's program, the staff finds that those portions of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, on the basis of its review of the exceptions and enhancement to the GALL Report program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs will be maintained consistent with the CLB during 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).

3.0.3.2.12 Structures Monitoring—Structures Monitoring

Summary of Technical Information in the Application

Section B.1.32, "Structures Monitoring—Structures Monitoring," of the LRA describes the applicant's Structures Monitoring—Structures Monitoring Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program."

The applicant stated in the LRA that NRC RG 1.182, Revision 2, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," and NEI, Nuclear Management and Resource Council (NUMARC) 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," issued April 1996, address the implementation of structures monitoring under 10 CFR 50.65 (the Maintenance Rule). These two documents provide guidance for the development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function.

The applicant stated that the following structures are within the scope of this program:

- containment building
- auxiliary building
- turbine building and screenhouse
- yard structures and bulk commodities
- nonsafety-related systems and components affecting safety-related systems

The applicant will expand the program to encompass structures and structural components within the scope of license renewal.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.32 of Appendix B of the LRA, the applicant stated that the Structures Monitoring—Structures Monitoring Program will be consistent with GALL AMP XI.S6 with enhancements. The applicant will enhance the Scope of Program element to include the supports (equipment, cable tray, conduit and pipe), instrument panels, racks, cable trays, conduits, elastomers, pipe hangers, fire protection pump house superstructure and walls, gas bottle storage tank rack and foundation, security diesel generator room, switchyard control house, fire protection water storage tank foundation, primary water storage tank foundation, and roadway west of the screenhouse. The applicant will also enhance the Detection of Aging Effects program element such that the examination criteria for the roadway west of the screenhouse must include detection of degradation of the roadway caused by weather-related damage.

By letter dated October 31, 2003, the applicant committed to including the additional SCs within the scope of its Structures Monitoring—Structures Monitoring Program. This is Commitment #23 in Appendix A of this SER. The staff finds that the proposed scope identifies the specific components for which the program manages aging and that the additional SCs are consistent with GALL AMP XI.S6. In addition, the enhancement to revise the procedure to include criteria that will detect degradation of the roadway is consistent with GALL AMP XI.S6 and will ensure that the roadway structure can perform its intended function consistent with the CLB. On this basis, the staff finds these enhancements to be acceptable.

During its audit, the staff asked the applicant to describe how it will adequately address the aging effects of the loss of material on the ice condenser steel structural components and the loss of material, cracking, and changes in material properties for ice condenser concrete structural components exposed to borated ice for the period of extended operation. The applicant stated that its Structures Monitoring (CNP AMP B.1.32) and Boric Acid Corrosion (CNP AMP B.1.4) Programs will ensure that the aging effects associated with the ice condenser will be managed during the period of extended operation. Specifically, CNP AMP B.1.35, "Structures Monitoring—Ice Basket Inspection," addresses the ice baskets. The staff finds this acceptable.

Operating Experience The applicant stated in the LRA that its operating experience review included CRs, LERs, NRC inspection reports, peer assessments, and self-assessments. The most recent NRC inspection of the Maintenance Rule implementation of the Structures Monitoring Program, conducted in 2001 (NRC Inspection Report, 50-315/01-16 and 50-316/01-16, October 16, 2001), identified no findings of significance for the specific areas related to the Maintenance Rule that were inspected.

The staff reviewed the self assessments related to the Structures Monitoring Program that were conducted in 1999 and 2001. Based on those self assessments, the applicant identified corrective actions which included revising the Structures Monitoring Program controlling procedure to incorporate the specific acceptance criteria recommended by the 2001 self-assessment. The applicant, during the self-assessment, identified another corrective action related to the fact that several miscellaneous structures were not addressed by the Structures Monitoring Program. The program controlling procedure was revised to include these miscellaneous structures.

On the basis of its review of the above operating experience and on discussions with the applicant's technical staff, the staff concludes that Structures Monitoring—Structures Monitoring Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.35 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Structures Monitoring—Structures Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the enhancements to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.13 Structures Monitoring—Crane Inspection

Summary of Technical Information in the Application

Section B.1.33, "Structures Monitoring—Crane Inspection," of the LRA describes the applicant's Structures Monitoring—Crane Inspection Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with exceptions and enhancements, with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

The applicant stated in the LRA that this program includes testing and monitoring to provide assurance that the SSCs of these cranes are capable of sustaining their rated loads. This program is primarily concerned with passive structural components that make up the bridge and trolley.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.33 of Appendix B to the LRA, the applicant stated that the Structures Monitoring—Crane Inspection Program will be consistent with GALL AMP XI.M23 with exceptions and enhancements. The program takes exception to the Parameters Monitored or Inspected program element in that it does not review the number and magnitude of the lifts. For the program element associated with the exception taken by the applicant, the GALL Report states that the number and magnitude of lifts made by the crane are reviewed. The staff finds that review of the number and magnitude of lifts is not necessary since the allowable limits are expected to provide adequate margin for the period of extended operation. Section 4.7.6 of the LRA addresses the number of lifts made by cranes as a time-limited aging analysis (TLAA). On this basis, the staff finds this exception to be acceptable.

The Structures Monitoring—Crane Inspection Program also takes exception to the Detection of Aging Effects program element in that it does not perform functional tests on all in-scope cranes. For the program element associated with the exception taken by the applicant, the

GALL Report states that crane rails and structural components are visually inspected on a routine basis for degradation. Functional tests are also performed to assure their integrity.

During the audit, the staff found that the intended function of many cranes is maintaining structural integrity to prevent impacting safety-related SSCs. Therefore, functional tests involving the active components of these cranes are not subject to aging management. On this basis, the staff finds the functional part of the exception to be acceptable.

Section 4.7.6 of this SER describes the staff evaluation of the exception that validates the structural integrity of crane components through visual inspection in lieu of functional tests.

The applicant stated in the LRA that it will enhance the Structures Monitoring—Crane Inspection Program Scope of Program element by developing procedures or recurring tasks to manage the loss of material on the crane, rails, and supports of in-scope cranes. The staff finds that the addition of procedures or recurring tasks to manage the loss of material on in-scope components is consistent with the requirements for this program element in GALL AMP XI.M23. On this basis, the staff finds this enhancement to be acceptable.

The applicant stated in the LRA that it will enhance the Structures Monitoring—Crane Inspection Program Parameters Monitored or Inspected program element by developing procedures or recurring tasks to evaluate the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of in-scope cranes. The staff finds that addition of procedures or recurring tasks to evaluate the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes is consistent with the requirements for this program element in GALL AMP XI.M23. On this basis, the staff finds this enhancement to be acceptable.

The applicant stated in the LRA that it will enhance the Structures Monitoring—Crane Inspection Program Detection of Aging Effects program element by developing procedures or recurring tasks to verify that in-scope crane rails and structural components are visually inspected on a routine basis for loss of material. The staff finds that the addition of procedures or recurring tasks to visually inspect crane rails and structural components for degradation on a routine basis is consistent with the requirements for this program element in GALL AMP XI.M23. On this basis, the staff finds this enhancement to be acceptable.

The applicant stated in the LRA that it will enhance the Structures Monitoring—Crane Inspection Program Acceptance Criteria program element by developing procedures or recurring tasks to verify that significant visual indications of the loss of material from corrosion or wear are evaluated according to applicable industry standards and good industry practice. The staff finds that the addition of procedures or recurring tasks to evaluate significant visual indications of degradation according to applicable industry standards and good practice is consistent with the requirements for this program element in GALL AMP XI.M23. On this basis, the staff finds this enhancement to be acceptable. These enhancements to the Structures Monitoring—Crane Inspection Program are part of Commitment #24 in Appendix A of this SER.

<u>Operating Experience</u> The applicant states in the LRA that its operating experience review included a review of CRs, LERs, NRC inspection reports, and self-assessments.

The staff reviewed operating experience relative to the Structures Monitoring—Crane Inspection Program and did not identify any crane aging problems. One industry operating experience incident identified involved a crane rail stud failure caused by fatigue. As the corrective action, the applicant had the crane representative inspect major cranes and modified the preventive maintenance task sheet to ensure that inspections are performed before crane use.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that Structures Monitoring—Crane Inspection Program adequately manages the aging effects that have been observed at the applicant's plant or at other nuclear facilities.

UFSAR Supplement

In Section A.2.1.36 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Structures Monitoring—Crane Inspection Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exceptions and enhancements to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.14 Structures Monitoring—Masonry Wall

Summary of Technical Information in the Application

Section B.1.36, "Structures Monitoring—Masonry Wall," of the LRA describes the applicant's Structures Monitoring—Masonry Wall Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with an enhancement, with GALL AMP XI.S5, "Masonry Wall Program."

The applicant stated in the LRA that the Masonry Wall Program manages aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. The applicant inspects masonry walls as part of the Structures Monitoring Program conducted for the Maintenance Rule, 10 CFR 50.65.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the enhancement and its justifications to determine whether the AMP, with the enhancement, remains adequate to manage the aging effects for which it is credited.

In Section B.1.36 of Appendix B to the LRA, the applicant stated that it will enhance the Scope of Program element for the Structures Monitoring—Masonry Wall Program to include the 4-hour fire rated masonry block in the turbine building and screenhouse, and the masonry block in the auxiliary building. For the program element associated with the enhancement by the applicant, the GALL Report states that the scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The staff finds that the inclusion of the masonry block in the turbine building, screenhouse, and auxiliary building is consistent with the GALL Report. The applicant identified these structural components as within the scope of license renewal because they perform intended functions in accordance with 10 CFR 54.4. On this basis, the staff finds the enhancement to be acceptable. This enhancement is Commitment #25 in Appendix A of this SER.

Operating Experience The applicant stated in the LRA that the operating experience review for the Structures Monitoring—Masonry Wall Program included CRs, NRC inspection reports, and documentation of the results of internal program assessments.

The applicant stated in the LRA that it identified physical degradation during a walkdown in 1999. Three block walls had mortar joints that were cracked and needed to be resealed. As a result of these findings, the applicant conducted additional inspections for loss of function (but did not find any) and repaired the three walls. This demonstrates that activities performed under the program actively identify and manage aging effects before loss of function.

Based on a review of the applicant's CRs, the staff concludes that the applicant has identified operating experience for the Structures Monitoring—Masonry Wall Program and has performed corrective actions where needed.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Structures Monitoring—Masonry Wall Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.39 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Structures Monitoring—Masonry Wall Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the enhancement to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.15 Water Chemistry Control—Primary and Secondary Water Chemistry Control

Summary of Technical Information in the Application

Section B.1.40.1 of the LRA describes the applicant's Water Chemistry Control—Primary and Secondary Water Chemistry Control Program. In the LRA, the applicant stated that this existing CNP program will be consistent, with enhancements, with GALL AMP XI.M2, "Water Chemistry."

The applicant stated in the LRA that this program mitigates damage caused by corrosion and stress-corrosion cracking (SCC). The program relies on monitoring and control of water chemistry based on Electric Power Research Institute (EPRI) guidelines.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

In Section B.1.40.1 of Appendix B to the LRA, the applicant stated that the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program will be consistent with GALL AMP XI.M2 with enhancements. The applicant stated in the LRA that it will enhance the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program Parameters Monitored or Inspected program element by revising program controlling procedures to require individual implementing procedures to identify and prescribe any special collection and preservation procedures to collect a sample. The applicant stated that it will also enhance the Acceptance Criteria program element to include sulfate monitoring criteria for the refueling water storage tank (RWST) that are consistent with the EPRI guidelines and the sulfate criteria for other systems impacted by RWST chemistry (*i.e.*, RCS and SFP). Furthermore, the applicant will enhance the Parameters Monitored or Inspected and Acceptance Criteria program elements according to the applicable EPRI water chemistry guidelines.

The staff finds that the enhancements to the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program, all of which are intended to ensure that the program complies with the applicable EPRI water chemistry guidelines and thus ensure consistency with the GALL AMP, will improve the ability of the systems to perform their intended functions consistent with the CLB during the extended operating term. On this basis, the staff finds the enhancements to be acceptable.

Operating Experience The applicant stated in the LRA that the program is based on the EPRI water chemistry guidelines, which reflect chemistry practices based on operating experience in the nuclear power industry. The guidelines are updated as appropriate based on continuing operating experience.

The applicant stated in the LRA that it performed a primary chemistry self-assessment in 2002 that focused on critical program attributes. It evaluated selected attributes established in EPRI PWR primary water guidelines. The assessment included an industry peer and obtained benchmarking information from two other plants. The assessment team concluded that the essential program attributes assessed are adequately described and effectively implemented.

The applicant also stated in the LRA that it performed a self-assessment of the secondary chemistry program in 2002, including peer review with staff from another station, to identify program deficiencies and to establish corrective actions. The assessment team examined industry operating experience to improve startup contaminant control. The assessment team concluded that the essential program attributes assessed are adequately described and effectively implemented.

The staff reviewed the applicant's documentation and concludes that the applicant has identified operating experience for the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program and performed corrective actions where needed.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Water Chemistry control—Primary and Secondary Water Chemistry Control Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.43 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are, indeed, consistent with the GALL Report. In addition, the staff has reviewed the enhancements to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.16 Water Chemistry Control—Closed Cooling Water Chemistry Control

Summary of Technical Information in the Application

Section B.1.40.2 of the LRA describes the applicant's Water Chemistry Control—Closed Cooling Water Chemistry Control Program. In the LRA, the applicant stated that this existing CNP program will be consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with exceptions.

The applicant stated in the LRA that this program includes preventive measures that manage loss of material (including that caused by selective leaching, where applicable), cracking, and fouling, as applicable, for closed cooling water system components. These chemistry activities provide for monitoring and controlling closed cooling water chemistry using procedures and processes that are based on EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines."

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In Section B.1.40.2 of Appendix B to the LRA, the applicant stated that the Water Chemistry Control—Closed Cooling Water Chemistry Control Program will be consistent with GALL AMP XI.M21 with exceptions. The Water Chemistry Control—Closed Cooling Water Chemistry Control Program takes exception to the Parameters Monitored or Inspected, Monitoring and Trending, and Acceptance Criteria program elements in that the program only monitors chemistry parameters. For the program elements associated with the exception taken by the applicant, the GALL Report states that the AMP monitors the effects of corrosion by surveillance testing and inspection in accordance with the standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure. Performance and functional tests are performed at least every 18 months to demonstrate system operability. Tests to evaluate heat removal capability of the system and degradation of system components are performed every 5 years. System and component performance test results are evaluated in accordance with the guidelines of EPRI TR-107396. Acceptance criteria and tolerances are also based on system design parameters and functions.

During the audit, the staff asked the applicant to justify the acceptability of the exception to these program elements (Parameters Monitored or Inspected, Monitoring and Trending, and Acceptance Criteria) in GALL AMP XI.M21. The applicant stated that monitoring only the chemistry parameters is sufficient to protect system components from degradation without monitoring the parameters of pumps and heat exchangers in the system.

In its response, the applicant stated that EPRI TR-107386 does not provide specific recommendations for equipment performance and functional testing at a given frequency for monitoring the effectiveness of a water chemistry control program. Monitoring pump performance parameters is of little value in managing the effects of aging on long-lived, passive closed cooling water system components. Section 5.7 of EPRI TR-107396 states that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In addition, EPRI TR-107386 further states that performance monitoring "can be used to confirm that conditions in the closed cooling water system are not degrading heat exchanger performance."

The staff finds that this EPRI guidance neither requires nor negates performance monitoring. The staff reviewed the applicant's operating experience and inspection procedures of plant systems and heat exchangers together with industry guidelines and determined that there is reasonable assurance that monitoring chemistry parameters in conjunction with plant inspections will adequately manage aging effects on the closed cycle cooling water systems. On this basis, the staff finds this exception to be acceptable.

In addition, the Water Chemistry Control—Closed Cooling Water Chemistry Control Program takes exception to the Detection of Aging Effects program element by stating that it is a preventive program that claims no credit for the detection of aging effects through performance and functional testing. For the program element associated with the exception taken by the applicant, the GALL Report states that the extent and schedule of inspections and testing, in accordance with EPRI TR-107396, assure the detection of corrosion before the loss of intended function of the component. Performance and functional testing, in accordance with EPRI TR-107396, ensures the acceptable functioning of the closed cooling water system or components serviced by the closed cooling water system.

During the audit, the staff asked the applicant to justify the exception to the Detection of Aging Effects program element in GALL AMP XI.M21 and explain why performance and functional testing is not required to effectively manage aging effects.

In its response, the applicant stated that, in most cases, functional and performance testing verifies that component active functions are maintained and therefore would be managed by the Maintenance Rule (10 CFR 50.65). The applicant further responded that GL 89-13 does not require testing of closed cycle cooling water system heat exchangers because of the effectiveness of the Closed Cooling Water Chemistry Control Program. The Closed Cooling Water Chemistry Control Program will adequately manage the passive intended functions of pumps, heat exchangers, and other components of the closed cycle cooling water system.

The staff reviewed the applicant's response and operating experience and concludes that aging effects on passive mechanical components in the closed cooling water system are adequately managed without reliance on performance and functional testing. On this basis, the staff finds the exception to the Detection of Aging Effects program element to be acceptable.

Lastly, the Water Chemistry Control—Closed Cooling Water Chemistry Control Program takes exception to the Acceptance Criteria program element such that the nitrite corrosion inhibitor concentrations are maintained within specified limits, which allow for a larger variance (1200–4000 parts per million (ppm)) than recommended (500–1000 ppm) in EPRI TR-107396. For the program element associated with the exception taken by the applicant, the GALL

Report states that corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for closed cooling water systems.

During the audit, the staff asked the applicant to provide the technical basis for using different limits than EPRI TR-107396 on nitrite corrosion inhibitor concentrations and to justify that its concentration limits will not increase the probability of corrosion in system components.

In its response, the applicant stated that EPRI TR-107396, Section 4.3.2, notes the following:

> Based on industry experience, lower ranges (200 to 500 ppm) have been successfully used in systems with demineralized water makeup. Higher levels (up to 4000 ppm) can be used, but increase the potential for microbiological growth.

The applicant further stated that procedural targets for nitrites are within these EPRI guidelines, and that CNP AMP B.1.41, "Water Chemistry Control—Chemistry One-Time Inspection," will confirm the effectiveness of the Closed Cooling Water Chemistry Control Program before the period of extended operation. Additionally, the applicant has converted water chemistry control for component cooling water systems to molybdate corrosion inhibitor control, and the limits for molybdate match the recommended limits in EPRI TR-107396. The applicant has stated that nitrate control remains a procedural option until sufficient operating experience with molybdate control is evaluated.

The staff reviewed the Water Chemistry Control—Chemistry One-Time Inspection Program and documents its evaluation in Section 3.0.3.3.17 of this SER.

The staff reviewed the applicant's response, operating experience (discussed below), and industry guidelines and determined that there is reasonable assurance that monitoring these nitrite corrosion inhibitor concentrations within specified limits will adequately manage aging effects on closed cooling water systems. On this basis, the staff finds this exception to the Acceptance Criteria program element to be acceptable.

<u>Operating Experience</u> The applicant stated in the LRA that its operating experience for the Water Chemistry Control—Closed Cooling Water Chemistry Control Program reflects chemistry practices based on extensive operating experience in the nuclear industry. The guidelines are updated, as appropriate, based on continuing operating experience. An independent assessment, performed by the applicant in 1999, of the component cooling water system chemistry included a detailed review of the program chemical selection, control, monitoring, and recordkeeping and provided an examination of the fidelity of the processes with industry guidance documents.

The applicant further stated that the independent review provided evaluations of plant-specific operating experience and recommendations based on that experience. The review found the documentation of the chemical treatment processes to be exemplary, while the overall program is comparable to industry best practices.

The staff reviewed operating experience in representative CRs relevant to the Water Chemistry—Closed Cooling Water Chemistry Control Program and finds that the program monitors and corrects out-of-specification readings before they contribute to the aging of components.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Water Chemistry Control–Closed Cooling Water Chemistry Control Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.44 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Water Chemistry Control—Closed Cooling Water Chemistry Control Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are indeed consistent with the GALL Report. In addition, the staff has reviewed the exceptions to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.2.17 Fatigue Monitoring

Summary of Technical Information in the Application

Section B.2.2, "Fatigue Monitoring," of the LRA describes the applicant's Fatigue Monitoring Program. In the LRA, the applicant stated that this existing program is consistent, with an exception, with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." The applicant stated that in order to remain within fatigue usage design limits, the Fatigue Monitoring Program monitors and tracks the number of critical thermal and pressure transients for selected RCS components. The program ensures the validity of analyses that explicitly assume a specified number of thermal and pressure fatigue transients. This program manages those components that are shown to be acceptable by analyses explicitly based on a limiting number of thermal or pressure fatigue transient cycles.

In addition, the applicant stated, in the LRA, that the Fatigue Monitoring Program for aging management is a continuation of an existing program. The projections from the plant operating experience to 60 years of operation show that the fatigue transients will be within bounds for the extended license of the plant. The applicant also states that continued implementation of the Fatigue Monitoring Program will assure that the applicable SCs will be monitored for fatigue damage and will perform their intended functions within the design basis during the extended period of operation.

Staff Evaluation

During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The audit and review report documents the staff's evaluation of this effort. Furthermore, the staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

In Section B.2.2 of Appendix B of the LRA, the applicant stated that the Fatigue Monitoring Program is consistent with GALL AMP XI.M1 with an exception. The Fatigue Monitoring Program takes exception to the Detection of Aging Effects program element in that the program does not provide for periodic update of fatigue usage calculations. The program initiates corrective actions only when the number of accumulated cycles approaches 80 percent of the number of component design cycles.

The GALL Report states that the program provides for the periodic update of the fatigue usage calculations. The applicant stated that updates of fatigue usage calculations, as recommended in the GALL Report, are not necessary unless the number of accumulated fatigue cycles approaches the number of assumed design cycles, and it commited to implement corrective actions at that time. This is an alternative method for ensuring that the design code limit is not exceeded.

On the basis of its review of this AMP, the associated engineering report, and the operating experience, the staff determined that this AMP is consistent with the GALL Report and that the exception in the Fatigue Monitoring Program is acceptable.

Operating Experience The applicant stated in the LRA that it performed a self-assessment of the Fatigue Monitoring Program in 1999. This self-assessment identified deficiencies and provided recommendations that were addressed with CRs. These CRs led to enhancements of the implementing procedure, even though the procedure met the intent of the program requirements. The applicant also stated that, in 2002, it performed a followup self-assessment to review the program improvements. This followup self-assessment concluded that the program will adequately and accurately track design-basis plant transients. This assessment also identified deficiencies and provided recommendations that were addressed by corrective actions, which demonstrates that the program continues to be monitored and improved.

In addition, the applicant stated that it has tracked thermal fatigue transients since the initial hydrostatic tests and commercial operation of both CNP units. The applicant stated that it performed a review of the number of design transients documented to date. Based on the rate of occurrence, it projected the numbers of the various transients to 60 years of operation. The applicant demonstrated that the numbers of design transients projected for the period of extended operation associated with license renewal are less than the numbers of transients considered in its fatigue analyses.

The staff reviewed the applicant's documentation and concludes that the applicant has identified operating experience for the Fatigue Monitoring Program and performed corrective actions, where needed.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that CNP AMP B.2.2 is sufficient to support the management of the aging effects of fatigue that have been monitored and predicted at the applicant's plant.

UFSAR Supplement

In Section 2.1.12 of Appendix A to the LRA, the applicant provided its UFSAR Supplement for the Fatigue Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR Supplement adequately summarizes the program activities. The staff finds this section of the UFSAR Supplement sufficient, pursuant to 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that those attributes of the program for which the applicant claimed consistency with the GALL Report are, indeed, consistent with the GALL Report. In addition, the staff has reviewed the exception to the GALL Report program and finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3 AMPs That Are Plant Specific

In Appendix B to the LRA, the applicant indicated that the following AMPs are plant specific:

- Alloy 600 Aging Management Program
- Bolting and Torquing Activities Program)
- Boral Surveillance Program
- Bottom-Mounted Instrumentation Thimble Tube Inspection Program
- Heat Exchanger Monitoring Program
- Inservice Inspection—ASME Section XI, Augmented Inspection Program
- Instrument Air Quality Program
- Oil Analysis Program
- Pressurizer Examinations Program
- Preventive Maintenance Program
- Structures Monitoring—Divider Barrier Seal Inspection Program
- Structures Monitoring—Ice Basket Inspection Program
- System Testing Program
- System Walkdown Program
- Wall Thinning Monitoring Program
- Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program
- Water Chemistry Control—Chemistry One-Time Inspection Program

For the plant-specific AMPs that are not consistent with or not addressed by the GALL Report, the staff performed a complete review of the AMPs to determine if they are adequate to monitor or manage aging. The following sections of this SER document the staff's review of these plant-specific AMPs.

3.0.3.3.1 Alloy 600 Aging Management

<u>Summary of Technical Information in the Application</u>

Section B.1.1 of Appendix B to the LRA discusses the Alloy 600 Aging Management Program. The applicant stated that the Alloy 600 Aging Management Program is a new, plant-specific program that it will implement before the period of extended operation. There is no comparable GALL Report program. The applicant stated that this program will manage the aging effects of Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the RCS that are not addressed by other AMPs. This program will detect primary water stress corrosion cracking (PWSCC) before the loss of the component intended function by using the examination and inspection requirements specified in ASME Code, Section XI.

<u>Staff Evaluation</u>

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the Alloy 600 Aging Management Program to determine if the program demonstrates that it will adequately manage aging effects so that the component intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Section A.2.1.1, the applicant stated that it will implement the new Alloy 600 Aging Management Program before the period of extended operation. The Alloy 600 Aging Management Program will detect cracking from PWSCC by using the examination and inspection requirements specified in ASME Code, Section XI. This program excludes components which are covered by the following AMPs:

- Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program
- Steam Generator Integrity Program
- Reactor Vessel Internals Programs

RAI B.1.1.2-1

The applicant's commitment does not identify that the lessons learned from industry initiatives and research will become part of the Alloy 600 Aging Management Program. Since the applicant's program has not been developed, the applicant has not demonstrated that the Alloy 600 Aging Management Program will identify and assist in managing the effects of age-related degradation mechanisms (ARDMs). Therefore, in RAI B.1.1.2-1 dated July 2, 2004, the staff requested the following:

> The staff requests the applicant to modify commitment A.2.1.1 and the Program Description to state that lessons learned from industry initiatives and research will be used as part of the Alloy 600 Aging Management Program. The commitment needs to state that the Alloy 600 Aging Management Program will be submitted for staff review and approval three years prior to the period of extended operation to determine if the program demonstrates an ability to manage the effects of aging per 10 CFR 50.54.21(a)(3).

In its supplemental letter dated August 11, 2004, the applicant's response to RAI B.1.1.2-1 states that, in the Monitoring and Trending program element, the applicant will use guidance developed by the EPRI MRP and the owners groups to identify critical locations for inspection and augment existing ISI at CNP, where appropriate. Similarly, in the Operating Experience program element, the LRA states that the applicant will consider industry and plant-specific operating experience in the development of this program as appropriate. The applicant committed to implement a new Alloy 600 Aging Management Program. This is Commitment #3 in Appendix A of this SER, which states:

> I&M will continue to participate in industry initiatives, such as Westinghouse Owners Group and the EPRI/MRP. Susceptibility rankings and program inspection requirements regarding Alloy 82/182 pipe butt welds will be consistent with the later version of the EPRI MRP safety assessment or its successors.

The applicant revised the last paragraph of LRA Section A.2.1.1. This revision is part of Commitment #1 in Appendix A of this SER and is as follows:

> The Alloy 600 Aging Management Program will detect cracking from primary water stress corrosion cracking (PWSCC) using the examination and inspection requirements in ASME Section XI. Guidance developed by the EPRI Materials Reliability Program and the owners groups will be used to identify susceptibility rankings and program inspection requirements regarding Alloy 82/182 pipe butt welds. This program will be implemented prior to the period of extended operation.

The applicant stated that it will also revise the Alloy 600 Aging Management Program commitment to indicate that it will submit an inspection plan for staff review and approval 3 years before the period of extended operation to determine if the program demonstrates the ability to manage the effects of aging in accordance with 10 CFR 54.21(a)(3). This is Commitment #2 in Appendix A of this SER.

The staff concludes that the commitments made in response to RAI B.1.1.2-1 will ensure implementation of the appropriate changes (*i.e.*, those that assure the structural integrity of the RVHs and other Alloy 600 components in the primary coolant system during the extended period of operation). Therefore, the staff considers RAI B.1.1.2-1 closed.

The staff reviewed the program against the 10 elements that are described in Appendix A to the SRP-LR.

<u>Scope of Program</u> The applicant stated that the Alloy 600 Aging Management Program scope includes Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the RCS that other AMPs do not address. The applicant identified the specific SCs that this program would manage. This element is acceptable to the staff because the program will address Alloy 52/152 and 82/182 welds that other AMPs do not address.

<u>Preventive Actions</u> The applicant identified this element as a condition monitoring program. Therefore, the identification of preventive actions is not required. This element is acceptable to the staff because it agrees with the licensee that this is a condition monitoring program.

<u>Parameters Monitored or Inspected</u> The applicant stated that the Alloy 600 Aging Management Program will detect degradation by using the examination and inspection requirements specified in ASME Code, Section XI. It will monitor the presence and extent of cracking. This

element is acceptable to the staff because the licensee will use the inspection and examination requirements specified in ASME Code, Section XI.

RAI B.1.1.2-2

Detection of Aging Effects The applicant stated that the Alloy 600 Aging Management Program will detect cracking by PWSCC before the loss of the component intended function. The components will receive a volumetric examination during each inspection interval in accordance with the 1989 edition of ASME Code, Section XI, Examination Category B-F. Therefore, in RAI B.1.1.2-2 dated July 2, 2004, the staff requested the following:

> The staff requests the applicant to provide justification, including codes and standards referenced, that the technique and frequency used in the Alloy 600 Aging Management Program are adequate to detect the aging effects before a loss of system or component function occurs.

In its supplemental letter dated August 11, 2004, the applicant's response to RAI B.1.1.2-2 stated that the inspection techniques and frequencies for the components that will be included in the Alloy 600 Aging Management Program and that will receive volumetric inspection are those described in ASME Code, Section XI, Examination Category B-F. The applicant also stated that dissimilar metal welds subject to volumetric inspections in each inspection interval will meet the flaw acceptance criteria defined in ASME Code, Section XI, Subsection IWB-3514.

The applicant also stated that the Scope of Program element in LRA Section B.1.1 describes the reactor vessel, pressurizer, and steam generator components that will be included in the Alloy 600 Aging Management Program. The program will include the consideration of industry operating experience in developing the inspection frequency, techniques, and acceptance criteria. For example, NRC Bulletin 2003-02 details industry experience with leaking reactor lower head penetrations fabricated from nickel-based alloy material. The NRC issued Bulletin 2004-01in May 2004. These recent bulletins indicate the evolving nature of regulatory guidance related to Alloy 600 materials.

The applicant stated that the aging of Alloy 600 is an issue relevant to current plant operation. In accordance with the license renewal principles discussed in the SOC for the final rule for 10 CFR Part 54, the existing regulatory process, which includes consideration of industry operating experience, will ensure that the Alloy 600 Aging Management Program can effectively manage the cracking of Alloy 600 material from PWSCC.

The licensee stated that it will base the development of the Alloy 600 Aging Management Program inspection techniques and frequencies on ASME Code, Section XI, current and ongoing industry operating experience and the existing regulatory process.

The staff concludes that the clarifications made in the response to RAI B.1.1.2-2 will ensure the implementation of the appropriate changes (*i.e.*, those that assure the structural integrity of the RVHs and other Alloy 600 components in the primary coolant system during the extended period of operation). Therefore, the staff considers RAI B.1.1.2-2 closed.

Monitoring and Trending The applicant stated that it will maintain inspection records, examination and test procedures, examination/test data, and corrective actions taken or recommended in accordance with the requirements of ASME Code, Section XI, Subsection IWA.

The applicant stated that the EPRI MRP, in conjunction with the PWR owners groups, is developing a strategic plan to manage and mitigate PWSCC of nickel-based alloy items. As its main goal, the MRP provides short- and long-term guidance for inspection, evaluation, and management of Alloy 600 base material and Alloy 52/152 and 82/182 weld metal locations in PWR primary systems. The applicant stated that it expects to use the guidance developed by the MRP and owners groups to identify critical locations for inspection and augment existing ISI inspections at CNP as appropriate.

Acceptance Criteria The applicant stated that the acceptance criteria for volumetric and visual inspections will be based upon the requirements in ASME Code, Section XI.

RAI B.1.1.2-3

At a minimum, 10 CFR 50.55a requires the applicant to comply with the flaw acceptance criteria specified for ASME Class 1 components in ASME Code, Section XI, Subsections IWA-3000 and IWB-3000, regardless of whether the material is fabricated from Alloy 600. The applicant may use alternative acceptance criteria determined either by the applicant or the industry if the staff has reviewed and accepted the alternative criteria pursuant to 10 CFR 50.55a(a)(3). The acceptance criteria stated are not definitive enough to determine if the applicant would allow pressure boundary leakage if the fracture mechanics analysis proved that the component could perform its intended function. Therefore, in RAI B.1.1.2-3 dated July 2, 2004, the staff requested the following actions of the applicant:

> The staff requests the applicant to discuss the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended functions will be maintained under all CLB design conditions. The discussion needs to focus on how pressure boundary leakage due to PWSCC will be handled.

In its supplemental letter dated August 11, 2004, the applicant's response to RAI B.1.1.2-3 stated the acceptance criteria for volumetric inspections of dissimilar metal weld (Alloy 82/182) locations, as required by ASME Code, Section XI, Examination Category B-F, will be in accordance with ASME Code, Section IX, Subsection IWB-3514. The applicant stated that ASME Code, Section XI, Subsection IWB-3514.4, discusses allowable flaw standards for dissimilar metal welded joints and references allowable flaw standards for austenitic piping in Table IWB-3514-2. Section J of EPRI NP-1406-SR, "Nondestructive Examination Acceptance Standards," issued May, 1980, contains the flaw acceptance standards for austenitic piping in ASME Code, Section XI, Table IWB-3514-2, which are based on the net-section ductile yielding criterion. The applicant stated that the allowable flaw sizes in ASME Code, Section XI, Table IWB-3514-2, are based on the net-section ductile yielding criterion, since linear elastic fracture mechanics could not be used without modifications to account for plastic effects, and elastic-plastic fracture analysis was not fully developed when ASME Code, Section XI, Table IWB-3514-2, acceptance standards were developed. The applicant stated that leakage is not permitted regardless of flaw size.

The applicant continued by stating the following:

> I&M will continue to participate in industry initiatives, such as the Westinghouse Owners Group and the EPRI MRP. Susceptibility rankings and program inspection requirements regarding Alloy 82/182 pipe butt welds will be consistent with the later version of the EPRI MRP safety assessment or its successors. Through the use of operating experience, should the industry develop alternative acceptance criteria for ASME Code, Section XI, Category B-F, based on the EPRI MRP regarding inspection of dissimilar metal welds, I&M will evaluate applicability to CNP and implement the pertinent acceptance criteria accordingly.

The applicant stated that unacceptable indications require detailed analysis, repair, or replacement. The acceptance standards established in ASME Code, Section XI, Subsection IWB-3500, ensure that all service conditions (A through D) are protected by maintaining the safety margin of the component throughout the service life of the component. When the applicant is evaluating an operating component for an indication that it exceeds the allowable acceptance standards in Subsection IWB-3500, it refers to Section XI and requires the use of the original safety margins for all operating conditions (*i.e.*, normal, upset, emergency, and faulted conditions). The applicant stated the safety margins vary for specific cases (*i.e.*, component and geometry) but are always consistent or conservative with respect to the original design margins.

The applicant stated that should additional nickel-based alloy locations (weld and base metal) be identified for inspection (volumetric, surface, or visual) based on industry operating experience, for which acceptance standards are not included in ASME Section XI, acceptance standards will be developed using appropriate analytical techniques (*i.e.*, elastic-plastic fracture mechanics). As an option, the applicant will use the latest ASME Code methodology, as accepted pursuant to 10 CFR 50.55a.

The applicant stated that additional inspections of nickel-based alloy locations required in response to regulatory correspondence (*i.e.*, NRC bulletins and GLs) or to industry initiatives (*i.e.*, MRP) during the current term of operation will carry forward into the period of extended operation.

The staff concludes that based on the response to RAI B.1.1.2-3, the applicant will implement the appropriate changes (*i.e.*, those that assure the structural integrity of the RVHs and other Alloy 600 components in the primary coolant system during the extended period of operation); therefore, the staff considers RAI B.1.1.2-3 closed.

Corrective Actions The applicant stated that component repair and replacement procedures are in accordance with ASME Code, Section XI, requirements, and it will implement corrective actions in accordance with the CNP Corrective Action Program. The applicant implements the CNP quality assurance procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The applicant stated that the CNP corrective actions are consistent with the GALL Report. This element is acceptable to the staff because it is in accordance with the requirements of Appendix B to 10 CFR Part 50 and is consistent with the GALL Report.

Confirmation Process The applicant stated that the CNP Corrective Action Program addresses confirmation processes to ensure that preventive actions and appropriate corrective actions are adequate. The applicant stated that it implements the CNP quality assurance procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The applicant stated that the CNP confirmation process is consistent with the GALL Report. This element is acceptable to the staff because it is in accordance with the requirements of Appendix B to 10 CFR Part 50 and is consistent with the GALL Report.

Administrative Controls The applicant stated that it implements the CNP quality assurance procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The applicant performs administrative control for both safety related and nonsafety related SCs according to the existing Document Control Program in accordance with the Quality Assurance Program description (QAPD). The applicant stated that the CNP administrative controls are consistent with the GALL Report. This element is acceptable to the staff because it is in accordance with the requirements of Appendix B to 10 CFR Part 50 and is consistent with the GALL Report.

Operating Experience The applicant stated that the Alloy 600 Aging Management Program is a new program for which there is no CNP-specific operating experience. The applicant will consider industry and plant-specific experience in the development of this program as appropriate.

UFSAR Supplement

In Section A.2.1.1 of Appendix A to the LRA, the applicant provided its UFSAR Supplement for the Alloy 600 Aging Management Program. The staff reviewed the UFSAR Supplement and finds that the summary description contains a sufficient level of information to satisfy 10 CFR 54.21(d); therefore, it is acceptable.

Conclusion

On the basis of its review of the applicant's program, the staff concludes that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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 concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

The staff has reviewed the information provided in Section B.1.1 of Appendix B to the LRA, as supplemented by the applicant's responses to the RAIs in its letters dated August 11, 2004. On the basis of this review, the applicant demonstrated that it will have a program in place, approved by the staff, which demonstrates that it will adequately manage the effects of aging associated with Alloy 600 Class 1 components so that there is reasonable assurance that the intended functions will by maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.3.2 Bolting and Torquing Activities

Summary of Technical Information in the Application

Section B.1.2, "Bolting and Torquing Activities," of the LRA discusses the applicant's Bolting and Torquing Activities Program. The applicant stated that this program is an existing plant-specific program. The GALL Report has no comparable program. The NRC previously evaluated and approved a similar program in NUREG-1743, "Safety Evaluation Report Related to the License Renewal of Arkansas Nuclear Power Plant, Unit 1," issued April 2001. Furthermore, the Bolting and Torquing Activities Program relies on industry recommendations as delineated in EPRI guidelines for a comprehensive bolting integrity program.

The program covers bolting in high-temperature systems and in applications subject to significant vibration, as identified in the AMR. Preventive actions include the proper selection of bolting material and the use of the appropriate lubricants and sealants in accordance with EPRI guidelines.

Torque values are monitored when the bolted closure is assembled. Maintenance personnel visually inspect components used in the bolted closures to assess their general condition during maintenance. Gaskets, gasket seating surfaces, and fasteners are inspected for damage that would prevent proper sealing.

The applicant stated that the Bolting and Torquing Activities Program is a preventive program. Actions performed under the program prevent the aging effect of loss of mechanical closure integrity. This program is credited with managing the loss of mechanical closure integrity for bolted connections and bolted closures. According to the applicant, the CNP site procedures provide the acceptance criteria, and the LRA does not discuss them. The applicant stated that repair and replacement are in conformance with EPRI guidelines, and it will implement specific corrective actions in accordance with the CNP Corrective Action Program.

The applicant reviewed operating experience relative to CNP bolting and torquing activities, including CRs, LERs, and NRC inspection reports. The review revealed limited problems with bolting and torquing activities. The applicant has and will continue to factor operating experience, both at CNP and in the nuclear industry, into program improvements.

In conclusion, the applicant stated the following:

> The Bolting and Torquing Activities Program effectively manages aging effects. Continued implementation of this program provides reasonable assurance that the aging effects associated with bolted closures will be managed such that applicable structures and components will perform their intended functions consistent with the current licensing basis for the period of extended operation.

Staff Evaluation

The applicant credited CNP AMP B.1.2, "Bolting and Torquing Activities," an existing plant-specific program, with managing the loss of mechanical closure integrity. The program covers bolting in high-temperature systems and in applications subject to significant vibration. The staff notes that the GALL Report credits GALL AMP XI.M.18, "Bolting Integrity," for monitoring the loss of material, cracking, and the loss of preload. In addition, accepted bolting integrity programs (such as EPRI 104213) recommend monitoring for loss of preload as one of the parameters monitored or inspected. Monitoring for cracking of high-strength bolts (actual yield strength equal or greater than 150 ksi) is also recommended.

RAI B.1.2-1

Based on the above, the staff asked the applicant in RAI B.1.2-1 to provide the following information:

(A) Identify the areas of the Bolting Integrity Program at CNP which are consistent with GALL AMP XI.M18, as well as those aspects in which it is different.

(B) Discuss how the CNP Bolting and Torquing Activities Program would manage the loss of preload aging effect.

(C) Discuss the inspections associated with the Bolting and Torquing Activities Program at CNP which may be beyond the requirements of ASME Code, Section XI.

(D) Identify any high-strength bolts included within the boundary of the ESFs, auxiliary, or steam and power conversion systems.

(E) Because the LRA does not identify the loss of preload as an AERM for bolts in the CNP auxiliary system, explain how this aging effect would be managed in this system.

(F) Discuss how the consideration of SCC as an applicable aging effect took into account the factors that can cause SCC in stainless steel bolts, such as stainless steel grade, method of hardening (*i.e.*, strain, precipitation or age hardening) environment, and stress levels.

In its response, the applicant stated the following:

> (A) The Bolting and Torquing Activities Program is an existing plant-specific program that was not compared to the NUREG-1801, Section XI.M18, Bolting Integrity Program. The program described in NUREG-1801, Section XI.M18, covers all bolting within the scope of licensee renewal including safety related bolting, bolting for nuclear steam supply system component supports, bolting for other pressure retaining components, and structural bolting. It includes periodic inspection of closure bolting for many aging effects, including loss of preload, cracking, and loss of material. Cracking of non-Class 1 stainless steel bolting is not an aging effect requiring management (see response to paragraph (f) below). Loss of material is managed by other programs identified in LRA Appendix B, as indicated in the LRA Section 3 aging management review results tables. Thus, the plant-specific. Bolting and Torquing Activities Program, which is used only to prevent loss of mechanical closure integrity, is not comparable to NUREG-1801, Section XI.M18.
>
> In LRA Section B.1.2, the ten attributes of the Bolting and Torquing Activities Program were provided to allow for assessment of this program, independent of NUREG-1801, Section XI.M18.

(B) The Bolting and Torquing Activities Program manages loss of preload by assuring that proper torque values are applied to bolted closures. With proper design of bolted closures, selection of appropriate torque values prevents loss of preload due to vibration or thermal cycles.

(C) The Bolting and Torquing Activities Program is a preventive program. The associated inspections are a check of the bolt torque performed after joint assembly and verification of proper gasket compression after torquing.

(D) CNP piping material specifications do not permit, nor have they historically permitted, high-strength bolting in non-Class 1 systems. Review of operating experience did not identify problems with cracking of high strength bolting in air environments.

(E) Bolting in high temperature systems and in applications subject to significant vibration is subject to loss of mechanical closure integrity due to loss of preload. As discussed in paragraph (b), above, the Bolting and Torquing Activities Program manages loss of preload by assuring that proper torque values are applied to bolted closures. With proper design of bolted closures, selection of appropriate torque values prevents loss of preload due to vibration or thermal cycles. The Bolting and Torquing Activities Program implements this approach to manage loss of mechanical closure integrity due to loss of preload for the mechanical systems presented in LRA Tables 3.2.2-2, 3.3.2-7, 3.3.2-8, 3.3.2-9, 3.3.2-11, and 3.4.2-1 through 3.4.2-4.

(F) Stress corrosion cracking (SCC) occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. Proper lubricants and sealant compounds are used to minimize the potential for SCC. The Bolting and Torquing Activities Program specifies appropriate lubricants and sealants to preclude introduction of significant contaminants.

The AMRs assumed the presence of sufficient stress to initiate SCC if stainless steel bolting were subject to a corrosive environment. However, SCC very rarely occurs in austenitic stainless steels below 60 °C (140 °F). In the instances where SCC is observed in stagnant, oxygenated, borated water below 60 °C (140 °F), the presence of a significant contaminant (halogens, specifically chlorides) is identified to be affecting the failed components. Since stainless steel bolted closures are exposed to ambient temperature rather than high-temperature process fluids, cracking of non-Class 1 stainless steel bolting is not an AERM.

The applicant limited its discussion of cracking to SCC. The GALL Report (in Section VIII H.2-b) also discusses cracking in closure bolting in high-pressure or high-temperature systems caused by cyclic loading. Therefore, the discussion should also include the potential for cracking caused by cyclic loading.

The applicant stated that the Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that the loss of mechanical closure integrity as a result of loss of preload due to high temperature does not occur. GALL AMP XI.M18 encompasses all safety related bolting. The CNP Bolting and Torquing Activities Program is limited to only high temperature bolting and applications subject to significant vibration. Other CNP programs address different aspects of GALL AMP XI.M18. For example, the CNP Inservice Inspection Program for Class 1, 2, and 3 bolted closures includes the ASME Code, Section XI, requirements. In addition, the Boric Acid Corrosion Prevention and System Walkdown Programs include periodic inspections of pressure-retaining components (including the closure bolting) for signs of leakage that may be caused by loss of preload, cracking, or the loss of material. The applicant has clarified that loss of preload is prevented in other safety related bolting as a result of its maintenance practices. The staff finds the applicants response reasonable and acceptable because its maintenance practices are comprehensive to assure the prevention of the loss of preload and the potential for cracking caused by cyclic loading.

Scope of Program The applicant stated that the Bolting and Torquing Activities Program covers bolting in high-temperature systems and in applications subject to significant vibration, as identified in the AMRs. The applicant did not identify the applicable AMPs that are credited with managing age-related degradation of bolting or threaded fasteners.

RAI B.1.2.2-1

In RAI B.1.2.2-1, the staff asked the applicant to identify the AMPs that are credited with managing age-related degradation of bolting and/or threaded fasteners and identify the material and the systems where they are present.

In its response, the applicant stated the following:

> Aging management reviews of the following systems credit the Bolting and Torquing Activities Program with managing loss of mechanical closure integrity for carbon and stainless steel bolting:

Exposed to High Temperatures or Vibration from Diesel Engines

System	**LRA Section**	**LRA Table**
Fire protection (fire pump diesel engines)	3.3.2.1.7	3.3.2-7
Emergency diesel engine	3.3.2.1.8	3.3.2-8
Security diesel engine	3.3.2.1.9	3.3.2-9

Exposed to High Temperatures

System	**LRA Section**	**LRA Table**
Containment isolation	3.2.2.1.2	3.2.2-2
Miscellaneous systems in scope for 10 CFR 54.4(a)(2)	3.3.2.1.11	3.3.2-11
Main feedwater	3.4.2.1.1	3.4.2-1
Main steam	3.4.2.1.2	3.4.2-2
Auxiliary feedwater	3.4.2.1.3	3.4.2-3
Steam generator blowdown	3.4.2.1.4	3.4.2-4

The RCS AMR credits the Bolting and Torquing Activities Program, in conjunction with the Inservice Inspection Program and the Boric Acid Corrosion Prevention Program, with managing loss of mechanical closure integrity for the following:

- low-alloy steel (LAS) and stainless steel bolting for Class 1 valves and blind flanges, as listed in LRA Table 3.1.2-3
- LAS bolting for reactor coolant pump main flange and pressurizer manway bolting, as listed in LRA Table 3.1.2-3 and 3.1.2-4
- LAS and carbon steel bolting for steam generator components, as listed in LRA Table 3.1.2-5

The applicant has clarified that all safety related bolting as addressed in GALL AMP is included in its scope.

Preventive Actions The applicant stated that the program preventive actions include the proper selection of bolting material and the use of appropriate lubricants and sealants, in accordance with EPRI guidelines. The initial inspection of bolting for pressure-retaining components includes a check of the bolt torque and uniformity of the gasket compression after assembly. Hot torque checks are not applied to all bolted closures within the scope of this program, but are controlled procedurally if the action is recommended by a vendor or if it is determined that hot torque is necessary on a case-by-case basis.

RAI B.1.2.2-2

The preventive actions did not clearly indicate which EPRI guidelines the applicant would use to select the proper bolting material, lubricants, and sealants. The applicant did not identify the actions and materials that it would use for replacement to demonstrate acceptable management of ARDMs.

Therefore, in RAI B.1.2.2-2, the staff asked the applicant to identify the EPRI guidelines to be used for selection of bolting material, lubricants, and sealants, including specific actions and material replacements, to demonstrate acceptable management of ARDMs. The applicant was also asked to provide an example of a case that would require a hot torque check of a bolted closure.

In its response, the applicant stated the following:

> The EPRI guidelines used are NP-5067, Good Bolting Practices, and TR-104213, Bolted Joint Maintenance & Applications Guide.
>
> Fastener material replacements are performed in accordance with piping specifications or approved configuration changes. Piping specifications require that boric acid corrosion resistant fastener material be used for bolted joints on systems containing borated water. Also, low yield strength bolting and low chloride and sulfur content threaded fastener lubricants are specified to minimize the potential for SCC.
>
> The site maintenance procedure for the feedwater stop check valves provides an example of hot torque requirements. The procedure requires re-torquing of the bonnet cap screws at normal operating temperature and pressure as a final post-maintenance condition, as recommended by the vendor technical manual.

The RAI response identifies appropriate EPRI references and also addresses the exceptions identified in NUREG-1339, as referenced in GALL AMP XI.M18.

<u>Parameters Monitored or Inspected</u>. The applicant stated that torque values are monitored when the bolted closure is assembled. Maintenance personnel visually inspect components involving bolted closures to assess their general condition during maintenance. They inspect gaskets, gasket seating surfaces, and fasteners for damage that would prevent proper sealing.

RAI B.1.2.2-3

The staff found that this element did not provide adequate detail to assure that ARDMs are managed. Since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the loss of material and crack initiation and growth.

Therefore, in RAI B.1.2.2-3, the staff asked the applicant to (1) inspect the bolting closures during maintenance, (2) confirm that the program inspections are integrated with the CNP Inservice Inspection Program and the results are tracked within this program, (3) confirm that the visual inspections are performed in accordance with ASME Code, Section XI, and (4) justify the exclusion of the loss of material and crack initiation and growth from this element.

In its response, the applicant stated the following:

> The Bolting and Torquing Activities Program manages loss of mechanical closure integrity due to loss of preload for closure bolting in high-temperature systems and applications subject to significant vibration.
>
> Loss of material is excluded from this program because other programs, such as the Boric Acid Corrosion Prevention Program and the System Walkdown Program, which are described in LRA Sections B.1.4 and B.1.38, respectively, manage loss of material for closure bolting and loss of mechanical closure integrity for closure bolting exposed to boric acid. Specific applications are identified in LRA Section 3 aging management review results tables. Loss of material (and ultimately loss of mechanical closure integrity) for external surfaces, such as closure bolting, is a long-term aging effect that would be observed well before aging progressed to the point of loss of intended function. Therefore, visual inspections for loss of material and loss of mechanical closure integrity, as required by the Boric Acid Corrosion Prevention Program and System Walkdown Program, are adequate to assure that the closure bolting can perform its intended function.
>
> Crack initiation and growth are excluded from this program because the Inservice Inspection Program manages cracking of bolted closures in Class 1 systems. Both the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program and the Inservice Inspection—ASME Section XI, Subsection IWE Program, which are described in LRA Sections B.1.14 and B.1.15, respectively, provide for ASME Section XI inservice inspections of Class 1 bolted closures. Specific applications are identified in LRA Section 3.1 aging management review results tables. Cracking is not an aging effect requiring management for non-Class 1 bolting applications due to low operating

> temperatures compared to Class 1 bolting applications and the use of low yield strength bolting and low chloride and sulfur content threaded fastener lubricants.

The applicant's response states that cracking is not an AERM for non-Class 1 bolting applications because of the low operating temperatures and proper use of lubricants. The staff finds the applicants response reasonable and acceptable because it clarifies the reason that cracking caused by vibration and cyclical loading is not applicable to non-Class 1 systems.

<u>Detection of Aging Effects</u> The applicant stated that the Bolting and Torquing Activities Program is a preventive program. Actions performed under the program prevent the aging effect of loss of mechanical closure integrity. The applicant credited this program with managing the loss of mechanical closure integrity for bolted connections and bolted closures.

RAI B.1.2.2-4

The program is intended to manage the loss of mechanical closure integrity for bolted connections and bolted closures. However, the applicant did not provide justification to support the program's ability to accomplish this.

Therefore, in RAI B.1.2.2-4, the staff asked the applicant to provide justification, including codes and standards referenced, that the technique and frequency used at CNP are adequate to detect the aging effects before a loss of component function occurs.

In its response, the applicant stated the following:

> The Bolting and Torquing Activities Program manages loss of mechanical closure integrity due to loss of preload for closure bolting in high-temperature systems and applications subject to significant vibration. Specific applications are identified in the LRA Section 3 aging management review results tables.
>
> Program standards are EPRI NP-5067, Good Bolting Practices, and TR-104213, Bolted Joint Maintenance & Applications Guide. These standards are used throughout the industry and have proven effective in managing loss of preload for closure bolting. Review of operating experience did not identify problems with loss of preload for bolted closures at CNP.

The applicant's response states that a review of operating experience did not identify problems with loss of preload for bolted closures at CNP and that this is consistent with industry experience where such maintenance practices and other factors are similar.

<u>Monitoring and Trending</u> The applicant stated that torque values are monitored during the bolt torquing process, and that trending is not applicable to this program.

RAI B.1.2.2-5

The staff finds that the applicant did not provide adequate detail under this element to assure that ARDMs are adequately managed. The applicant previously stated that maintenance personnel perform visual inspections to assess the general conditions in the bolted closures.

In RAI B.1.2.2-5, the staff asked the applicant to confirm that the program inspections are integrated with the CNP Inservice Inspection Program and discuss the method for integrating the results of these visual inspections. Further, the applicant should provide justification for not trending the results of the visual inspections.

In its response, the applicant stated the following:

> Under the Bolting and Torquing Activities Program, loss of mechanical closure integrity is managed by proper torquing during assembly of the bolted closure. This program is a preventive program, rather than an inspection program. Visual inspections to manage the effects of aging are not included in this program. In LRA Section B.1.2, program element Parameters Monitored or Inspected, the phrase, "visually inspect components used in the bolted closures to assess their general condition during maintenance," is a description of how bolting and torquing activities are performed. Prior to assembly, the mating surfaces and bolting components are inspected for manufacturing defects, nicks, dents, or scratches. After assembly, the closure is inspected for uniformity of gasket compression, proper thread engagement, and proper locking tab installation.
>
> Torque values are the only parameters monitored because the aging effect being managed is loss of mechanical closure integrity, or loss of preload, not loss of material or cracking. As described in I&M's response to RAI B.1.2.2-3, loss of material and cracking are managed by other programs such as the Boric Acid Corrosion Prevention Program, System Walkdown Program, and Inservice Inspection Program, where applicable. Thus, the Bolting and Torquing Activities Program does not include inspection results to trend.

The staff finds the applicant's response reasonable and acceptable because the applicant has confirmed that the program inspections are integrated with the CNP Inservice Inspection Program and noted the method for integrating the results of these visual inspections. Further, the applicant has provided justification for not trending the results of the visual inspections.

<u>Acceptance Criteria</u> The applicant stated that the CNP site procedures provide the acceptance criteria, such as mating surfaces smooth and free of major defects, proper and adequate thread engagement, and use of appropriate torque values.

The NRC staff found that the applicant's acceptance criteria were not definitive enough to determine whether the applicant would allow pressure boundary leakage if the component could perform its intended function.

RAI B.1.2.2-6

In RAI B.1.2.2-6, the staff asked the applicant to discuss how it will handle pressure boundary leakage and the requirements it will use to determine when leakage is acceptable and when repair or replacement is necessary.

In its response, the applicant stated the following:

> As discussed in the Statements of Consideration for the Final Part 54 Rule, the first principle of license renewal is that, with the exception of age-related degradation unique to license renewal and possibly a few other issues related to safety only during the period of extended operation of nuclear power plants, the regulatory process is adequate to ensure that the licensing bases of all currently operating plants provides and maintains an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security. Leakage is documented and evaluated through the Corrective Action Program. The quantity of leakage deemed acceptable and the need for repair or replacement is determined in accordance with requirements of the existing plant processes and activities that are addressed by the existing regulatory process. As a matter of conservative operating practice, administrative limits for which CNP would take action are established significantly below regulatory requirements.

The staff finds the applicant's response reasonable and acceptable because the applicant has discussed how it handles pressure boundary leakage and the requirements it will use to determine when leakage is acceptable and when repair or replacement is necessary.

Conclusion

On the basis of its review and inspection of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTP) RLSB-1 in Appendix A.1 to the SRP-LR, and that the program will adequately manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement for this AMR and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, on the basis of its review, the staff concludes that the applicant has demonstrated that the Bolting and Torquing Activities Program will adequately manage the effects of aging 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).

3.0.3.3.3 Boral Surveillance

Summary of Technical Information in the Application

Appendix B.1.3, "Boral Surveillance," of the LRA presents the applicant's program to manage aging of the Boral neutron absorber in the SFP. The applicant stated that this existing plant-specific program has no comparable GALL program. This AMP is credited with managing the aging of the boral in the storage racks by evaluating boral coupons. The coupons are positioned to receive a higher radiation dose than the functional boral panels. The applicant stated that measurements of certain physical and chemical properties of Boral coupons provide an assessment of the stability and integrity of the boral in the storage cells.

According to the applicant, the most recent coupon testing indicated no significant changes in coupon dimensions, weight, specific gravity, or Boron-10 areal density. Minor corrosion pitting was observed, but it was considered insignificant. The applicant reviewed industry operating experience concerning hydrogen gas generated by interaction of the fuel pool water with boral. No changes at CNP were deemed necessary as a result of the industry experience.

Staff Evaluation

Scope of Program. The applicant stated that the Boral Surveillance Program includes the boral in the CNP SFP. This element is acceptable to the staff because boral is used only in the SFP.

RAI B.1.3-1

Preventive Actions. The applicant noted that the program is an inspection program and does not include prevention measures. However, industry experience has found that venting of the racks is a design feature that can help prevent a key aging effect (bulging). The staff, therefore, asked in RAI B.1.3-1 by letter dated May 19, 2004, that the applicant state whether the wrappers in the storage racks are vented to allow the escape of corrosion-generated hydrogen gas, or if any other measures are incorporated to prevent the wrappers from bulging. In a letter dated August 11, 2004, the applicant responded that the storage racks at CNP are vented. The staff considers this design feature to be helpful in preventing bulging of the storage racks. Information Notice (IN) 83-29 describes fuel binding in 1982 at Maine Yankee caused by fuel rack deformation. Drilling holes in the top of the plates reduced the deformation, presumably by releasing corrosion-generated hydrogen.

Parameters Monitored or Inspected. The applicant listed the boral coupon parameters that would be monitored or inspected as neutron attenuation, dimensions (length, width, thickness), weight, and specific gravity. Since the program seeks to manage aging of boral panels by monitoring coupons believed to accurately represent the panels, the staff asked the applicant, in RAI B.1.3-1 by letter dated May 19, 2004, to discuss the relationship between the boral coupon measurements and the integrity of the boral panels.

In a letter dated August 11, 2004, the applicant responded that the coupon tree is moved each refueling outage to be surrounded by the highest power discharged fuel assemblies. The applicant stated that the boral coupons degrade faster than the boral panels because the coupons are exposed to a higher cumulative radiation dose, and the coupons therefore provide a definitive indication of the acceptability of the boral panels in the storage racks. Since the applicant should ensure that the boral coupons receive a higher radiation dose than the boral panels, the staff agrees that monitoring the coupons should provide an early indication of potential degradation of the boral panels in the storage racks.

In RAI B.1.3-1, the staff also asked the applicant to explain its use of the measured values of coupon specific gravity to manage aging. The UFSAR Supplement (see page A-12 of the LRA) and the Boral Surveillance Program (see page B-23 of the LRA) list specific gravity as one of the parameters monitored. However, the applicant did not discuss specific gravity as part of the acceptance criteria in the AMP. According to the applicant, specific gravity is one of the physical parameters used to identify early indications of boral degradation. An unexplained decrease in specific gravity could indicate loss of material and would result in an engineering evaluation and possibly a change in the measurement schedule.

The staff considers this program element acceptable because experience has shown that boral degradation in the SFP environment occurs slowly and can be detected in the early stages by the methods proposed. The measurements of neutron attenuation, physical distortion, and weight change would detect coupon degradation that would precede a loss of functionality in the boral panels (neutron absorption and fuel assembly spacing). Moreover, unacceptable coupon results would initiate an engineering evaluation and, if considered necessary, direct testing of the storage racks (*i.e.* blackness testing).

<u>Detection of Aging Effects</u>. The staff asked the applicant, in RAI B.1.3-1 by letter dated May 19, 2004, to discuss the accuracy of the neutron attenuation and thickness measurements that would be used to monitor the coupons, as well as the accuracy required to detect degradation of the panels in the fuel racks. According to the acceptance criteria listed in the LRA, the applicant must be able to detect a 5-percent decrease in Boron-10 content and a 10-percent increase in thickness. In a letter dated August 11, 2004, the applicant responded that the required accuracy for the thickness measurement is ±0.005 inches, and the actual measurement accuracy is ±0.001 inches. In a letter dated January 21, 2005, responding to related RAI B.1.3-2, the licensee confirmed that the thickness and Boron-10 measurement capabilities meet or exceed the program specifications. The applicant explained that neutron attenuation is compared on a relative basis to a boral reference standard. The staff finds these acceptable because the accuracy of the measurement techniques is compatible with the acceptance criteria.

<u>Monitoring and Trending</u>. The applicant stated that it would conduct trending analysis by comparing the periodic inspection measurements and analysis to previous results. In a public meeting on September 1, 2004, the staff asked the applicant to confirm that the prescribed schedule for coupon removal and evaluation would include the extended operating period. In an e-mail dated September 27, 2004, the applicant responded that the program does continue during the extended operating period. The applicant stated that the "Conclusion" section of the program confirms this with the phrase "continued implementation," which refers to the period of extended operation.

A November 2004 AMP inspection raised a concern that the applicant may not be performing trending of the coupon measurements, and that the applicant's measurement capabilities may be inadequate for trending. In a letter dated January 12, 2005, the staff requested that the applicant clarify its capability for evaluating coupon thickness, provide the results of past coupon evaluations, and confirm that the 5-percent uncertainty in Boron-10 areal density is within the uncertainty tolerance used in the most recent criticality safety analysis. The staff also asked the applicant to provide dates for removal and evaluation of coupons in the past, as well as an explanation of how coupon removal and evaluation times are determined. In a letter dated January 21, 2005, the applicant responded that the calibrated measurement instruments are capable of measuring length, width, and thickness to ± 0.04, 0.02, and 0.002 inches, respectively, all of which are smaller than the 10% acceptance criterion. The applicant also stated that the limit of 5-percent Boron-10 areal density variation is conservative with respect to the SFP criticality analysis. The applicant uses the coupon size and Boron-10 area density measurements to identify trends in degradation based on exposure time.

Regarding the schedule and past results, the applicant responded in the January 21, 2005 letter that coupon removal and evaluation dates are based on vendor recommendations intended to produce more radiation dose than the expected lifetime dose for normal storage. During the period of extended operation, the evaluation interval will be 5 years, which the applicant stated is recommended by the Boral vendor and supported by the coupon results. The staff reviewed results from coupons tested in 1994 and 2001 and confirmed that there were no significant changes in coupon dimensions, weight, density, or Boron-10 areal density.

In the section of the LRA that discusses operating experience, the applicant stated that it noted minor corrosion pitting during the most recent inspection. The staff asked the applicant, in RAI B.1.3-1 by letter dated May 19, 2004, to describe this pitting and discuss the trending procedure required to ensure that the pitting will not increase to affect the functionality of the boral. In a letter dated August 11, 2004, the applicant responded that, after visual inspection, eight blisters formed on the coupon surface during heating to remove residual moisture. The applicant stated that the blisters resulted from localized damage to the aluminum cladding by mechanical impacts during manufacturing or by corrosion pitting. Following penetration of the cladding, moisture entered the core of the coupon at the location of the hole or pit. According to the applicant, subsequent corrosion sealed the moisture in the core, and heating caused the cladding to separate from the core and form a blister. Microscopy revealed a pit or small hole in the cladding at each blister location. The applicant stated that this amount of corrosion pitting would not affect the boral functionality. The applicant compares coupon test results with baseline data and past test results to ensure that boral function is not adversely affected. The applicant evaluates adverse conditions as part of the Corrective Action Program. The staff finds this element acceptable because the applicant monitors parameters that would indicate degradation and identifies trends in the parameters by comparison to baseline and interim test results.

<u>Acceptance Criteria</u> On page B-24 of the LRA, the applicant identified the acceptance criteria as a decrease of no more than 5 percent Boral-10 content, as determined by neutron attenuation, and a maximum increase of 10 percent in thickness at any point over the initial thickness at that location. The applicant identified additional parameters that are examined for early indications of potential boral degradation and possibly a change in measurement schedule, including visual or photographic evidence of surface deterioration (general or pitting corrosion, edge deterioration), unaccountable weight loss, and areas of reduced boron density in neutron radiographs.

In a public meeting on September 1, 2004, documented as follow-up item to RAI B.1.3-1 in a letter dated September 29, 2004, the staff asked the applicant to provide the technical basis for the acceptance criteria (5-percent maximum Boron-10 decrease and 10-percent maximum thickness increase). The staff asked the applicant to provide a reference if the NRC previously reviewed and approved the Boral Surveillance Program at CNP. In a letter dated October 18, 2004, the applicant stated that the CNP Boral Surveillance Program had not previously been reviewed and approved by the NRC, but similar programs had been approved for two other plants. The applicant stated in the October 18, 2004, letter that it selected a 5-percent decrease in Boron-10 areal density because this is the limit of precision in the measurement and it is also within the usual uncertainty tolerance applied in the nuclear criticality safety analyses. In a letter dated January 12, 2005, the staff requested that the applicant confirm that the 5-percent variation in Boron-10 areal density was used in the most recent criticality safety analysis for CNP. In a letter dated January 21, 2005, the applicant responded that a 5-percent variation is conservative because the Boron-10 density assumed in the most recent fuel pool criticality analysis (0.030 g/cm^2) is 15-percent less than the nominal Boron-10 density for the adsorber panels (0.0345 g/cm^2).

With respect to the coupon thickness measurement, the applicant stated that a 10 percent increase (0.0075 inches) in coupon thickness is sensitive enough to detect coupon swelling or blistering before the boral panels could swell or blister enough to cause binding of fuel assemblies. The applicant also noted that swelling or blistering does not affect the functionality (reactivity control) of the boral. The staff finds these criteria acceptable because they measure changes small enough to provide reasonable assurance that corrective actions could be taken before a loss of functionality occurs.

Corrective Actions Section B.0.3 of the LRA discusses the corrective actions, which are common to all AMPs. The applicant stated that the corrective actions are consistent with the GALL Report. The Boral Surveillance Program description provides additional information about the corrective actions for that program. The applicant stated that, in addition to implementing the CNP Corrective Action Program, the Boral Surveillance Program corrective actions will include an investigation and engineering evaluation if the coupon acceptance criteria are not met. Additional testing, such as blackness testing of the storage racks, may be performed based on the engineering evaluation.

Confirmation Process and Administrative Controls Section B.0.3 of the LRA discusses these elements, which are common to all AMPs. The program description did not provide any program-specific details.

Operating Experience The applicant stated that CRs resulted in the correction of procedural problems, including insufficiently defined responsibilities in the controlling procedure leading to missed samples, missing references to NRC commitments, and noncompliance with administrative guidelines.

The applicant stated that the most recent testing of boral coupons detected no significant changes in the measured parameters. The staff asked the applicant, in RAI B.1.3-1 by letter dated May 19, 2004, to justify this statement and describe the amount of change that was found. In a letter dated August 11, 2004, the applicant described the changes. The coupon dimensions changed by about -0.67-percent to +1.19-percent, with the difference attributed to oxide thickness or surface and edge irregularities; the dry weight and density increased about 0.5-percent from the original values; and the small increase in Boral-10 areal density was within the measurement precision.

Regarding the schedule and past results, the applicant responded in the January 21, 2005 letter that two coupon evaluations had been missed and discovered in 1999, and that corrective actions have since been implemented to ensure that future sampling opportunities will not be missed. These corrective actions include upgrades to the work control process, and improvements in process and program ownership.

Degradation of boral has occurred in the industry both in boral storage rack panels and boral coupons. Bulging of the cover plates (wrappers) on boral panels was found to be a result of hydrogen gas produced by corrosion of the boral. In the LRA, the applicant stated that it did not consider any program changes to be necessary as a result of industry experience with hydrogen gas generation, but it did not provide any reasons. The staff therefore requested, in RAI B.1.3-1 by letter dated May 19, 2004, that the applicant discuss the technical basis for concluding that industry experience with hydrogen gas does not affect the Boral Surveillance Program. In the same RAI, the staff asked the applicant to discuss the impact, if any, that degradation of boral at Seabrook Nuclear Station is considered to have on the Boral Surveillance Program at CNP. In September 2003, an inspection of boral test coupons at Seabrook revealed bulging and blistering of the aluminum cladding. In a letter dated August 11, 2004, the applicant responded that it documented industry operating experience with hydrogen gas generation and evaluated it within the Corrective Action Program.

The applicant described an industry operating event in which the interaction of SFP water and boral plates in a multipurpose canister formed hydrogen gas. Though the boral plates used in the multipurpose canister had been prepassivated, a small amount of unpassivated material remained after the prepassivation process. Passivation is the formation of a corrosion product film that protects a metal or alloy from further corrosion. The unpassivated material interacted with water to produce aluminum oxide and free hydrogen gas. The staff notes that the vented design of the boral panels will help to prevent bulging of the panels by allowing corrosion-generated hydrogen to escape. As discussed above with regard to Preventive Actions program element, the deformation of boral panels at Maine Yankee was reduced by venting the panels to release hydrogen.

The licensee also discussed a September 2003 operating event in which bulging and blistering of the aluminum cladding was found on boral test coupons at Seabrook. The applicant responded that the blisters observed on the Seabrook coupon were different than the blisters associated with pitting on the CNP coupons. As discussed above with regard to Monitoring and Trending program element, the blisters on the CNP coupons were attributed to the coupon heating process, which removes residual moisture from the coupon. The Seabrook coupon blisters were observed during visual inspection before heating and subsequent testing. Seabrook filed a report pursuant to 10 CFR Part 21, "Reporting of Defects and Noncompliance," on September 15, 2003 (2003-0022-00). The applicant stated that two tracking actions remain within the CNP Corrective Action Program. The first action will ensure that additional information on the 10 CFR Part 21 issue is received and evaluated for CNP. The second action will ensure that consideration is given to the Seabrook experience when the results of the next CNP boral coupon test are compared to previous results. The staff finds that the operating experience at CNP and other plants reveals significant information about managing the aging of boral storage racks and monitoring boral coupons, and that the applicant is applying this information in a way that will identify potential concerns with the functionality of the boral.

The staff finds this element of the program acceptable because the applicant has implemented corrective actions to ensure that future sampling opportunities are not missed. In addition, the applicant will examine and monitor CNP and industry experience (such as the Seabrook incident) in order to maintain or enhance the effectiveness of the Boral Surveillance Program. Therefore, the staff finds this program element acceptable.

UFSAR Supplement

The applicant provided the UFSAR Supplement for the Boral Surveillance Program in Section A.2.1.3 of Appendix A to the LRA. The staff reviewed this section and accepts it as an adequate summary of the program activities.

Conclusion

Based on its review of the applicant's Boral Surveillance Program, the staff finds that the program adequately addresses the 10 program elements defined in BTP RLSB-1 in Appendix A.1 to the SRP-LR, and that the program will adequately manage the aging effects for which it is credited. 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, based on its review, the staff finds that the applicant has demonstrated that the Boral Surveillance Program will adequately manage the effects of aging so that the intended functions of SCs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.3.4 Bottom-Mounted Instrumentation Thimble Tube Inspection

Summary of Technical Information in the Application

Section B.1.5, "Bottom-Mounted Instrumentation Thimble Tube Inspection," of the LRA discusses the applicant's Bottom-Mounted Instrumentation Thimble Tube Inspection Program. The GALL Report does not have a corresponding program. The staff's technical evaluation, below, describes the program.

Staff Evaluation

In LRA Section B.1.5, the applicant described its AMP to manage the integrity of the BMI thimble tubes, which serve as a portion of the RCPB. As discussed in NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," dated July 26, 1988, thimble tube wall thinning can occur as a result of flow-induced vibration (FIV). This wear damage is detected at locations associated with geometric discontinuities or area changes along the reactor coolant flowpath, such as areas near the lower core plate, the core support forging, the lower tie plate, and the vessel penetrations. The applicant developed its Bottom-Mounted Instrumentation Thimble Tubes Inspection Program based on the guidance in Bulletin 88-09 to inspect for wear damage.

The applicant designed its Bottom-Mounted Instrumentation Thimble Tube Inspection Program for the detection of wear, not SCC. However, LRA Table 3.1.2-1 lists cracking as an AERM for BMI thimble tubes and bullet plugs. Because of this inconsistency, the staff requested that the applicant confirm that cracking for BMI thimble tubes is a credible degradation mechanism requiring aging management and, if necessary, revise the program to include inspection for cracking due to SCC. The staff addressed this issue in RAI B.1.5-1. Section 3.1.2.3.1 of this SER provides the resolution of RAI B.1.5-1 as part of the AMR review.

The GALL Report does not evaluate this AMP. Therefore, the staff reviewed this AMP against the 10 program elements using the guidance in BTP RLSB-1 in Appendix A to the SRP-LR. The staff also reviewed the UFSAR Supplement to determine whether it adequately describes the program.

Scope of Program. The applicant stated that all thimble tubes are within the scope of this inspection program. The staff finds the scope of the program to be adequate because all thimble tubes are within scope and the applicant inspects the entire tube for wear resulting from FIV.

Preventive Actions. As noted below with regard to the Operating Experience element, the replacement of all thimble tubes with tubes with chrome plating at the wear areas constitutes a preventive action. However, the service time of approximately 4 years is not long enough to demonstrate the effectiveness of using chrome plating to mitigate the wear from FIV. RAI B.1.5-3, generated with regard to the Monitoring and Trending and Acceptance Criteria elements described below, reflects this concern.

Parameters Monitored or Inspected. The applicant will use eddy current examinations to determine the wall thickness of the thimble tubes, allowing an assessment of the wear and wear rate of each tube. The staff finds this acceptable because the eddy current examination has been successfully used to determine wall thickness and wear rate.

Detection of Aging Effects. The LRA states that thimble tube eddy current inspections are scheduled to be performed every third refueling outage. The applicant must provide the basis for this schedule using industry and plant-specific data. RAI B.1.5-3, generated with regard to the Monitoring and Trending and Acceptance Criteria elements described below, reflects this concern.

RAI B.1.5-2

Monitoring and Trending and Acceptance Criteria. The replacement, repositioning, or isolation of BMI tubes is based on plant-specific calculations using the generic wear rate in WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear." The acceptance criteria are also derived from the WCAP report and require (1) replacement or isolation of a thimble tube with 80 percent through-wall wear, (2) repositioning of a thimble tube with more than 40-percent through-wall wear, provided that it is projected to remain under 80-percent until the next inspection, and (3) replacement, isolation, or repositioning of a thimble tube with more than 40-percent through-wall wear if it is projected to exceed 80-percent by the next inspection. Using repositioning as an option for Criterion 3 for a tube which is projected to exceed 80-percent wear by the next inspection is appropriate if the tube wear rates at all thimble tube locations are established using plant-specific data collected during the past and are to be collected in future inspections for the chrome-plated thimble tubes. The staff addressed this concern in RAI B.1.5-2. The applicant made a final response to RAI B.1.5-2 in its letter dated October 18, 2004, that the acceptance criteria are based on WCAP-12866 and that the final relocation position of a thimble tube predicted to exceed 80-percent wear will be determined via the corrective action evaluation of the eddy current results. The response to RAI B.1.5-2 further clarifies that plant-specific wear data will be used to establish the tube wear rates for selecting candidate repositioning location(s) to ensure that the repositioned tube wear will not exceed 80-percent by the next inspection. Therefore, the staff considers RAI B.1.5-2 resolved.

RAI B.1.5-3

Although WCAP-12866 has not been formally approved by the NRC, the NRC staff finds the WCAP's 80-percent through-wall acceptance criteria to be acceptable because the remaining 20-percent will provide adequate structural integrity until the tube is capped or replaced. The staff further determines that the CNP acceptance criteria are acceptable because the applicant proposed to take action when wear exceeds only 40-percent through-wall. This is adequate considering the plant-specific operating experience of CNP during the past 10 years. In regard to the frequency of inspection for thimble tubes, the applicant's proposed thimble tube inspection every third outage is acceptable because no wear has been discovered in the past three refueling outages for all thimbles. When wear appears, the inspection interval must be reevaluated based on the observed thimble tube-specific wear rates. The applicant must provide a revised inspection schedule, anticipating wear and based on the severity of wear. The staff addressed this concern in RAI B.1.5-3.

In its response letter dated August 19, 2004, the applicant provided its BMI thimble tube inspection history. This information reveals that thimble tube inspections were performed every refueling outage until 1992 when 15 tubes were replaced for Unit 1 and 22 for Unit 2 with selectively chrome-plated thimble tubes. In addition, an inspection conducted in January 1998 after three cycles of operation showed no indications of wear. Hence, the applicant completed its plan of replacing all remaining thimble tubes with chrome-plated tubes in 2000. Again, an inspection conducted in 2002 after one cycle of operation showed no indications of wear. This experience provides the basis for the applicant's proposed thimble tube inspection every third outage.

Although the proposed inspection frequency is adequate for the next inspection, it may not be adequate for all future inspections. As a follow-up to RAI B.1.5-3, the staff questioned the applicant about the plant-specific wear rate and the severity of wear after wear appears in thimble tubes and about the need to reevaluate the inspection interval accordingly. In its response to this concern, the applicant states the following:

> ...[s]hould inspection results indicate that more frequent inspections are needed during the current term of operation or the period of extended operation, the ECT frequency will be revised in accordance with the Corrective Action Program.

The staff finds this appropriate because stating that the ECT frequency will be revised in accordance with the Corrective Action Program considering inspection results is equivalent to revising the inspection schedule according to inspection results. In addition, the applicant proposed to add the following sentence to the UFSAR Supplement for this AMP to clarify the proposed inspection frequency:

> [t]he inspection frequency is based on measured data and projected wear results.

The staff considers this description adequate. Therefore, the staff's concern in RAI B.1.5-3 is closed.

Operating Experience. The NRC documents thimble tube wear in Westinghouse reactors in IN 87-44, "Thimble Tube Thinning in Westinghouse Reactors," and NRC Bulletin 88-09. In response to these notifications, CNP performed an eddy current examination of thimble tubes every one or two outages until 2000 when it replaced all thimble tubes with tubes that are plated with chrome in the areas subject to wear. Based on successful operating experience with the chrome-plated tubes, the applicant revised the thimble tube eddy current inspection frequency to once every third refueling outage. The staff determined that 4 years of operating experience are insufficient to conclude that the new tubes are free from wear. The staff addressed this concern in RAI B.1.5-3, discussed above.

UFSAR Supplement

The staff also reviewed the UFSAR Supplement for this AMP, including the enhancement discussed with regard to the Monitoring and Trending and Acceptance Criteria elements, and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review of the applicant's program, the staff finds that the applicant has addressed appropriately the attributes common to all GALL programs. The staff concludes 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 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).

3.0.3.3.5 Heat Exchanger Monitoring

Summary of Technical Information in the Application

Section B.1.13, "Heat Exchanger Monitoring," of the LRA describes the applicant's Heat Exchanger Monitoring Program. In the LRA, the applicant committed that it will initiate the plant-specific program before the period of extended operation. This is Commitment #9 in Appendix A of this SER. The GALL Report has no comparable program. The applicant credited this program with inspecting heat exchangers for age-related degradation. If degradation is found, then the applicant will evaluate its effects on the heat exchanger's design functions, including seismic operability.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.13 of Appendix B to the LRA, regarding the applicant's demonstration of the Heat Exchanger Monitoring Program, to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Heat Exchanger Monitoring Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements. The applicant indicated that the site-controlled Quality Assurance Program, evaluated in

Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.13 of Appendix B to the LRA, that this program manages aging effects on heat exchangers in the containment spray, emergency core cooling, CEQ, CCW, EDG, ESF ventilation, control room ventilation, chemical and volume control, and auxiliary feedwater (AFW) systems.

The staff confirmed that Section 3 of the LRA identifies the component type and systems for which the Heat Exchanger Monitoring Program manages aging effects, which satisfies the criteria defined in Appendix A.1 to the SRP-LR. On this basis, the staff finds that the applicant's proposed scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.13 of Appendix B to the LRA, that for this program element the Heat Exchanger Monitoring Program is a monitoring program, and the program will involve no actions to prevent or mitigate aging degradation.

The staff finds that the Heat Exchanger Monitoring Program is a condition monitoring program. It provides early indication and detection of the onset of aging degradation. It does not rely on preventive actions. Therefore, staff finds this acceptable.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.13 of Appendix B to the LRA, that it will perform NDE. It may use eddy current testing to identify wall thinning and cracking in shell-and-tube heat exchangers where practical. Heat exchanger heads, covers, and tubesheets will be inspected using visual inspection methods where accessible. Where monitoring is impractical, the applicant will evaluate replacement.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The Heat Exchanger Monitoring Program is acceptable because the NDE of the heat exchangers are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects The applicant stated, in Section B.1.13 of Appendix B to the LRA, that this program manages the aging effects of loss of material and cracking for the tubes. An appropriate sample population of heat exchangers will be determined based on operating experience before the inspections. The extent and schedule of the inspections prescribed by the program are designed to maintain seismic qualification and ensure that aging effects will be discovered and repaired before the loss of intended function. The eddy current inspection of the tubes will occur every 10 years, or more frequently if inspection results indicate a need for more frequent inspections. The visual inspections of the accessible heat exchangers will be performed on the same frequency as the eddy current inspections. Where inspection is impractical, replacement will be considered. Finally, inspection can reveal cracking and loss of material that could result in degradation in the seismic qualification of the heat exchangers. This program does not address fouling.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will (1) develop testing techniques based on industry operating experience, (2) determine the sample population of heat exchangers based on operating experience before the inspections, and (3) perform an eddy current inspection of the tubes every 10 years, or more frequently if inspection results indicate a need for more frequent inspections. On this basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.13 of Appendix B to the LRA, that it will evaluate the results against established acceptance criteria and make an assessment regarding the applicable degradation mechanism, degradation growth rate, and the allowable degradation level. It will use this information to develop the future inspection scope and inspection intervals.

The staff confirms that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will trend the inspection results, thereby enhancing its ability to detect aging effects before a loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.13 of Appendix B to the LRA, that it will establish the tube plugging limit for each heat exchanger to undergo eddy current inspection based upon a component-specific engineering evaluation. This evaluation will determine conservative acceptance criteria that will identify when degraded tubes must be removed from service. In addition, the acceptance criteria for visual inspections of heat exchanger heads, covers, and tubesheets will require no evidence of degradation that could lead to the loss of function. If degradation that could lead to the loss of intended function is detected, the applicant will write a CR and resolve the issue in accordance with the site Corrective Action Program.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will find any degradation that is identified from visual inspections and could lead to the loss of intended function to be unacceptable and implement corrective measures using the Corrective Action Program. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience The applicant stated, in Section B.1.13 of Appendix B to the LRA, that the Heat Exchanger Monitoring Program is a new program for which there is no operating experience. Eddy current inspections and heat exchanger internal visual inspections are standard industry methods to manage aging effects in heat exchangers. These methods are consistent with NRC-accepted industry practices. The applicant will consider industry and plant-specific operating experience in the development of this program, as appropriate.

The staff reviewed the records associated with implementation of GL 89-13 to confirm that the applicant is collecting plant-specific data on heat exchangers, including the results of nondestructive evaluations, and using them in an appropriate manner.

The staff recognizes that the Corrective Action Program, which captures internal and external plant operating experience issues, will provide reasonable assurance that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

On the basis of its review and discussions with the applicant's technical staff, the staff concludes that Heat Exchanger Monitoring Program will adequately manage the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.16 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Heat Exchanger Monitoring Program and stated that the program will manage loss of material and cracking, as applicable, on heat exchangers exposed to treated water in various systems. The program will inspect heat exchangers for degradation using NDE, such as eddy current inspections and visual inspections. If degradation is found, then the applicant will perform an evaluation to determine its effects on the heat exchanger's design functions. The applicant stated in Appendix A that it will initiate the Heat Exchanger Monitoring Program before the period of extended operation.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.6 Inservice Inspection—ASME Section XI, Augmented Inspections

Summary of Technical Information in the Application

Section B.1.18, "Inservice Inspection—ASME Section XI, Augmented Inspections," of the LRA describes the applicant's Inservice Inspection—ASME Section XI, Augmented Inspection Program. In the LRA, the applicant stated that it will initiate this plant-specific program before the period of extended operation. The Gall Report has no comparable program. The applicant credited this program with managing the effects of aging on selected components that are outside the jurisdiction of ASME Code, Section XI. The existing program is used for other components that do not require aging management in accordance with 10 CFR Part 54. Augmented inspections are consistent, to the extent practical, with the appropriate ASME Code, Section XI requirements, specifically regarding (1) selection of inspection methods, (2) inspection frequency, (3) percentage of components examined within a population, and (4) acceptance criteria.

The applicant stated that it has implemented the applicable requirements of the 1989 edition of ASME Code, Section XI, approved NRC alternatives and relief requests, and other requirements specified in 10 CFR 50.55a for the third ISI interval.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.18 of Appendix B to the LRA regarding the applicant's demonstration of the Inservice Inspection—ASME Section XI, Augmented Inspection Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Inservice Inspection—ASME Section XI, Augmented Inspection Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that the Inservice Inspection—ASME Section XI, Augmented Inspection Program scope includes existing augmented inspections on selected components that are outside the jurisdiction of ASME Code, Section XI, and nondestructive inspections that will be implemented before the period of extended operation to manage aging effects on portions of the containment spray system.

The applicant stated that it will enhance the scope of this program to include volumetric inspections of the spray additive tanks, the portions of the containment spray system that are wetted by sodium hydroxide (*i.e.*, piping up to the first normally closed valve), and the portion of the discharge header in containment that may contain untreated water with concentrated contaminants.

By letter dated October 31, 2003, the applicant committed to the enhancements applicable to the Inservice Inspection—ASME Section XI, Augmented Inspection Program and the associated implementation dates. This is Commitment #10 of this SER.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Appendix B, Section B.1.18, to the LRA, that the Inservice Inspection—ASME Section XI, Augmented Inspection Program is a monitoring program and will involve no actions to prevent or mitigate aging degradation.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for the Inservice Inspection—ASME Section XI, Augmented Inspection Program because it is a condition monitoring program.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that the program uses nondestructive inspections to monitor for cracking and the loss of material (wall thinning).

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Measurements of wall thickness are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that it uses nondestructive inspections, such as volumetric examination methods for ASME Code, Section XI, inspections of Class 1, 2, and 3 components. The ISI long-term plan specifies the frequency of inspections. The applicant stated that it will enhance the program to include inspections to manage (1) the loss of material and cracking of the spray additive tanks and the portions of the containment spray system that are wetted by sodium hydroxide (*i.e.*, piping up to the first normally closed valve) and (2) the loss of material and cracking of the portions of the discharge header in containment that may contain untreated water with concentrated contaminants.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The program treats the in-scope spray additive tanks as Class 2 vessels and the in-scope containment spray piping components as Class 2 piping, in accordance with ASME Code, Section XI. Inspections associated with this AMP use a frequency and sample size based on existing codes and operating experience to detect the presence and extent of aging effects. On that basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that it will implement the new inspections before the period of extended operation. This program does not perform trending. However, the Corrective Action Program applies to this program. This provides reasonable assurance that the applicant will identify trends entailing repeat failures to meet acceptance criteria and address them with appropriate corrective actions.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Because of the slow-acting nature of aging mechanisms causing these aging effects, the frequencies specified in ASME Code, Section XI, will be adequate to manage the effects of aging. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that it evaluates flaws detected during examination by comparing the examination results to the acceptance standards established in ASME Code, Section XI.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff reviewed the applicant's Acceptance Criteria program element and finds that the applicant deems any flaws discovered in the process of performing the inspections as unacceptable and implements corrective measures. Acceptance criteria are based on existing codes. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience. The applicant stated, in Section B.1.18 of Appendix B to the LRA, that the augmented inspections to be added before the period of extended operation are new. However, extensive industry operating experience supports the monitoring techniques used in this program. Operating experience at CNP will provide input to adjust the program, as needed, and to develop new augmented inspections.

The staff reviewed the applicant's ISI summary review of flaws that it analyzed to the end of the service life of the component. The staff finds that the applicant's ISI inspection results identify no analytical flaw evaluations performed in accordance with Subsection IWB-3600 for the service life of the component. Although the data were reported for the Metal Fatigue Program, the staff finds that they apply to the Inservice Inspection—ASME Section XI, Augmented Inspection Program.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff finds that CNP AMP B.1.18 adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.21 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Inservice Inspection—ASME Section XI, Augmented Inspections Program and stated that the program will manage the effects of aging on selected components outside the jurisdiction of ASME Code, Section XI. To the extent practical, augmented inspections will be consistent with the applicable requirements of ASME Code, Section XI (*i.e.*, selection of inspection methods, inspection frequency, percentage of components examined within a population, and acceptance criteria). This program requires enhancements that will be implemented before the period of extended operation.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.7 Instrument Air Quality

Summary of Technical Information in the Application

Section B.1.19, "Instrument Air Quality," of the LRA describes the applicant's Instrument Air Quality Program. In the LRA, the applicant stated that this existing plant-specific program prevents and mitigates aging effects on control air system components by maintaining the system free of water and significant contaminants. The GALL Report has no comparable program. The applicant also stated that the control air system is part of the CA system.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.19 of Appendix B to the LRA, regarding the applicant's demonstration of the Instrument Air Quality Program, to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Instrument Air Quality Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that the program applies to those components within the scope of license renewal and subject to an AMR that are supplied with control air where pressure boundary integrity is required for the component to perform its intended function.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that it monitors and maintains system air quality in accordance with CNP testing and inspection plans, which are designed to ensure that the control air system and equipment meet specified operating requirements. These requirements are derived from guidelines presented in American National Standards Institute (ANSI) Standard ISA-S7.3-1975, "Quality Standard for Instrument Air."

After reviewing the applicant's surveillance procedures and holding discussions with the applicant's responsible engineer, the staff finds that the applicant employs effective methods to prevent degradation of instrument air quality. The staff also confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that the Preventive Actions program element is acceptable because maintenance of contaminant-free oil systems prevents and mitigates the identified aging effects.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that this program periodically monitors the control air system air quality pursuant to the performance requirements in ANSI Standard ISA-S7.3-1975, including (1) maximum dewpoint (monitored approximately weekly), (2) particulate size (afterfilter differential pressure monitored daily), and (3) dryer condition inspection (monitored approximately monthly). In addition, the applicant proposed to enhance plant procedures to more clearly specify frequencies for the dewpoint and dryer tours.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The parameters monitored or inspected are linked to the aging effects pertinent to component intended functions. The parameters monitored are not necessarily the specific parameters being controlled to achieve the prevention or mitigation of aging effects; however, the selection of parameters is appropriate. For example, the surveillance program monitors to confirm that air system temperatures remain above the dew point. In another instance, particulates are not directly measured, but filter replacement that provides effective control is required. Maintenance and procurement documents were reviewed to confirm that the specified equipment is suitable for maintaining air quality within the required limits. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that it follows ANSI Standard ISA-S7.3-1975 guidelines to ensure timely detection of degradation of the control air system function. Degradation of the piping and equipment would become evident by observation of excessive corrosion, discovery of unacceptable leakage rates, or failure of the system or equipment to meet specified performance limits. This program is credited with managing the loss of material of the carbon steel, copper, and brass/bronze components in the control air systems.

The staff confirmed that, with the enhancement to clearly specify frequencies for dewpoint and dryer tours, this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The program is primarily preventive in approach and emphasizes maintenance of air system quality rather than detection of degradation in the components it serves. On this basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that it maintains trends for dewpoint in a trending database. It checks the control air afterfilter differential pressure daily.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The surveillance and maintenance procedures specify the Monitoring and Trending activities. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria The applicant stated, in Appendix B, Section B.1.19, to the LRA that the dewpoint at line pressure must be at least -7.8 °C (18 °F) below the minimum temperature to which any part of the instrument air system is exposed at any season of the year. In no case should dewpoint at line pressure exceed 3 °C (35 °F).

The applicant also stated in the LRA that plant procedures prescribe the removal of the afterfilter from service based on a specified high differential pressure limit (commitment from GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment").

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR and that the applicant provided appropriate acceptance criteria in the form of prescribed numerical limits. On this basis, the staff finds the Acceptance Criteria program element acceptable.

Operating Experience. The applicant stated, in Section B.1.19 of Appendix B to the LRA, that the NRC issued GL 88-14 based on industry operating experience with air systems. The applicant also stated that the Instrument Air Quality Program is based on program elements specified in the GL. The applicant documents instrument air quality that does not meet the administrative control criteria for sampling through the Corrective Action Program, which includes trending for adverse conditions and repetitive failures of system components.

The applicant stated in the LRA that the lack of a significant number of CRs regarding loss of material caused by corrosion in the air systems indicates that the program has been effective in preventing the effects of aging. As an example, a CR documented failure of the Unit 2 east control air dryer which, if left uncorrected, could have led to a failure to comply with the dewpoint requirements for air quality.

The staff reviewed the applicant's responses to concerns arising from industry experience with air systems. The staff finds that the applicant has had only a small number of CRs related to air systems. This suggests that the preventive approach taken has been successful.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that Instrument Air Quality Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.22 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Instrument Air Quality Program and stated that the program periodically documents the control air system air quality for maximum dew point, particulate size, and dryer condition, pursuant to the performance requirements of ANSI Standard ISA-S7.3-1975. This program ensures that the control air supplied to components within the scope of license renewal is maintained free of water and significant contaminants. This program requires an enhancement that will be implemented before the period of extended operation. The commitment to perform the enhancement is item number 11 of Appendix A of this SER.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.8 Oil Analysis

Summary of Technical Information in the Application

Section B.1.23, "Oil Analysis," of the LRA describes the applicant's Oil Analysis Program. The GALL Report has no comparable program. The applicant credited this plant-specific program with maintaining oil systems free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.23 of Appendix B to the LRA regarding the applicant's demonstration of the Oil Analysis Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Oil Analysis Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, provided in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated that this program encompasses periodic sampling of the lubricating oil to which plant components subject to an AMR are exposed. The components are maintained in a list of plant equipment included in the program.

The applicant stated that Oil Analysis Program will manage aging effects on the ECCS components wetted by lubricating oil, RCP bearing oil coolers, EDG lubricating oil system components, fire pump diesel engine lubricating oil system components, security diesel engine lubricating oil system components, and AFW pump turbine lubricating oil components. The applicant used Institute of Nuclear Power Operations (INPO) 89-009, Good Practice MA-316, "Plant Predictive Maintenance," as a basis for the initial selection of equipment.

The staff confirmed that the applicant identified the specific components for which the Oil Analysis Program manages aging. The Oil Analysis Program includes the lubricating oil to which these components are exposed. The Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. On this basis, the staff finds that the applicant's proposed scope is acceptable.

Preventive Actions. The applicant stated that the program maintains oil systems free of contaminants (including water and particulates), thereby preserving an environment that is not conducive to corrosion.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that the Preventive Actions program element is acceptable because maintenance of contaminant-free oil systems prevents and mitigates the identified aging effects.

Parameters Monitored or Inspected. The applicant stated that the program monitors contaminants that contribute to the aging effects of concern, such as particle contaminants and water content.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The Oil Analysis Program activities detect the conditions that potentiate degradation and also detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated that periodic sampling and compliance with the acceptance criteria provide assurance that lubricating oil contaminants do not exceed acceptable levels. The applicant stated that this program manages the aging effects of (1) loss of material (including that caused by selective leaching) and fouling for the ECCS components wetted by lubricating oil, (2) loss of material for RCP bearing oil coolers, (3) loss of material (including that caused by selective leaching), cracking, and fouling for EDG lubricating oil system components, (4) loss of material (including that caused by selective leaching) and fouling for the fire pump diesel engine lubricating oil system components, (5) loss of material (including that caused by selective leaching) for security diesel engine lubricating oil system components, and (6) loss of material (including that caused by selective leaching) and fouling for AFW pump turbine lubricating oil components. The applicant scheduled routine oil sampling and may adjust the scheduled sampling dates and intervals according to recommendations from the analysis laboratory, plant management, and engineering personnel.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Sampling from a population does not apply to this AMP. Sampling is appropriately described and linked to the aging effects, and compliance with the acceptance criteria allow for the timely detection of their presence and extent. The applicant used appropriate industry standards in the development of sampling methods and frequencies. On this basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated that the oil trending database contains the data obtained through the implementation of this program.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the analysis results enhances the applicant's ability to detect aging effects before a loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated that it reviews data received from the testing laboratories and documents evaluations of reports indicating an adverse trend or significant exception. It has set alert levels to initiate corrective action based on wear particle count, viscosity, and water content. Appropriate corrective actions are initiated when concerns regarding equipment or lubricant conditions are indicated.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Any contaminant values that are projected to exceed limits (determined on the basis of the applicable standards and manufacturers' recommendations documented in the implementing procedures) result in corrective measures. On this basis, the staff finds the Acceptance Criteria program element acceptable.

Operating Experience. The applicant stated that a review of operating experience pertaining to the Oil Analysis Program determined that program enhancements have been made based on industry and plant-specific operating experience. For example, it evaluated the potential for possible incompatibility between EDG fuel oil and lubricating oil identified at another nuclear power plant and made a program change to ensure that the problem was addressed. The review of CRs indicates that the program has detected conditions at levels below which aging degradation is expected to occur.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Oil Analysis Program adequately manages the aging effects that have been observed at the applicant's plant and will continue to do so during the period of extended operation.

UFSAR Supplement

In Section A.2.1.26 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Oil Analysis Program and stated that the lubricating oil environment in the mechanical systems within the scope of license renewal is maintained to the required quality. By monitoring oil quality, the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.9 Pressurizer Examinations

Summary of Technical Information in the Application

Section B.1.24, "Pressurizer Examinations," of the LRA describes the applicant's Pressurizer Examinations Program. In the LRA, the applicant stated that this plant-specific program has no comparable GALL program. As discussed in WCAP-14574-A, "License Renewal Evaluation: Aging Management for Pressurizers," cracking of the pressurizer cladding (and items attached to the cladding) may propagate into the underlying ferritic steel. In addition, the pressurizer spray head is susceptible to cracking and reduction of fracture toughness. This program identifies degradation that could potentially cause loss of intended function of these pressurizer components.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.24 of Appendix B to the LRA regarding the applicant's demonstration of the Pressurizer Examinations Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Pressurizer Examinations Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, discussed in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

RAI B.1.24-1

Scope of Program. The applicant states that the pressurizer examinations assess the cladding and attachment welds to the cladding of the pressurizer. Examinations of the condition of the pressurizer spray head, spray head locking bar, and coupling will be added to the scope of this program. The staff could not determine whether the scope includes nickel-alloy bimetallic welds used to attach penetrations to the pressurizer, and, if not, whether these nickel-alloy-based bimetallic penetration attachment welds are managed through another AMP. The staff addressed this concern in RAI B.1.24-1. The applicant responded in its letter dated August 19, 2004, that no nozzles are attached to the pressurizer with nickel-based alloy welds. It stated further that the surge, spray, relief, and safety nozzle-to-piping safe end connections are buttered with nickel-alloy weld material prior to attachment of the stainless steel safe ends with nickel-alloy weld material, and the Alloy 600 Aging Management Program will manage the aging effects for these welds. The staff considers this response satisfactory because it has confirmed that all pressurizer components having nickel-alloy weld material are outside the scope of the Pressurizer Examinations Program, and will be managed by another AMP. Therefore, RAI B.1.24-1 is resolved, and Bulletin 2004-01, which concerns the inspection of Alloy 82/182/600 materials in pressurizer penetrations, is not relevant to this AMP.

Preventive Actions. In Section B.1.24 of Appendix B to the LRA, the applicant stated that the Pressurizer Examinations Program is an examination program and will involve no actions to prevent aging effects or mitigate aging degradation.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for the Pressurizer Examinations Program because it is a condition monitoring program.

Parameters Monitored or Inspected The applicant stated, in Section B.1.24 of Appendix B to the LRA, that to provide assurance that cracking of the pressurizer cladding and attachment welds to the cladding has not propagated into the underlying base metal of the pressurizer, it will perform volumetric examination of pressurizer items that are susceptible to thermal fatigue. Cracking of the pressurizer stainless steel cladding would most likely result from thermal fatigue. The stainless steel clad item with the highest fatigue cumulative usage factor is the circumferential weld at the shell-to-head junction. In accordance with ASME Code, Section XI, Examination Category B-B, the applicant will perform volumetric examination of essentially 100 percent of the circumferential shell-to-head weld at each inspection interval. In addition, the weld metal between the surge nozzle and the vessel lower head will be subjected to high-stress cycles. Periodic monitoring of this area provides monitoring for cracking of the cladding that may propagate to the underlying ferritic steel. The weld that connects the surge nozzle to the lower head will receive volumetric examination at each inspection interval in accordance with Examination Category B-D. These examinations will continue through the period of extended operation to manage cracking of cladding that may extend into the base metal at susceptible locations. The applicant stated that it will enhance the program to include a one-time condition assessment of the spray head, spray head locking bar, and coupling.

The staff confirmed that this program element satisfies the criteria defined in Appendix A to the SRP-LR. The evaluations of cladding and weld integrity are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

RAI B.1.24-2

Detection of Aging Effects. Detection of cracking in the pressurizer cladding is achieved through periodic volumetric inspection procedures that satisfy ASME Code Section XI requirements, and is therefore acceptable. The applicant will determine the condition of the internal spray head, spray head locking bar, and coupling by a one-time visual examination (VT-3) of these components in either Unit 1 or Unit 2. This examination will be performed prior to the period of extended operation to accepted ASME Code Section XI methods and standards. Since the spray head and its associated components are subject to severe thermal cycling, the applicant did not provide an adequate justification to demonstrate that a VT-3 examination is adequate to detect a potential flaw in the spray head which could lead to the failure of the components. In addition, the applicant provided insufficient information for the staff to conclude that the proposed one-time inspection of these components in either Unit 1 or Unit 2 is adequate. The staff addressed this concern in RAI B.1.24-2.

The applicant made a final response to RAI B.1.24-2 in the letter dated October 18, 2004, which indicates that the pressurizer spray components are not relied upon for the mitigation of design basis events (DBEs), and are not required to demonstrate compliance with the regulated events including fire protection, as addressed in Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." Consequently, the applicant concluded the following:

> The spray heads and associated components do not perform a license renewal intended function and are not required to satisfy the safety related systems, structures, or components scoping criteria of 10 CFR 54.4(a)(1), the nonsafety related scoping criteria of 10 CFR 54.4(a)(2), or the regulated events scoping criteria of 10 CFR 54.4(a)(3).

Nevertheless, the applicant plans to improve the Pressurizer Examinations Program to perform a one-time VT-3 visual examination of these components in one unit as part of its license renewal commitments. This is Commitment #15 in Appendix A of this SER.

The staff considers that it is adequate to perform a one-time VT-3 visual examination of spray head components in one unit because (1) the components are not required to satisfy the safety related, nonsafety related, or the regulated events scoping criteria, (2) to date, the industry has not reported any incidents of loose part generation due to fracture of the spray head components, and (3) corrective actions, including replacement, will be considered after an evaluation of the one-time examination results. Based on this consideration, the staff concludes that the response to RAI B.1.24-2 satisfactory, and RAI B.1.24-2 is closed. This attribute is consistent with the GALL Report.

Monitoring and Trending. The applicant stated, in Section B.1.24 of Appendix B to the LRA, that during the course of the inspections, nondestructive examinations will characterize the extent of surface or volumetric flaws. It will record anomalous indications that are signs of degradation on NDE reports in accordance with plant procedures. As the inspection of the pressurizer spray head, spray head locking bar, and coupling is a one-time inspection, no monitoring or trending will be completed for this activity. However, the applicant will determine the need for subsequent inspections after evaluating the results of the inspection. All other examinations are part of the ASME Code, Section XI, required inspections and will be monitored in accordance with ASME Code, Section XI.

The staff confirmed that this program element satisfies the criteria defined in Appendix A to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before a loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.24 of Appendix B to the LRA, that the acceptance criteria for volumetric examinations will be in accordance with ASME Code, Section XI, Subsections IWB-3510 and IWB-3512. The acceptance standards for the visual examinations will be in accordance with ASME Code, Section XI, examinations (VT-3).

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that any volumetric examination results that fall below the minimum allowable, as determined by the applicable design code, will be considered unacceptable and corrective measures implemented. On that basis, the staff finds that the Acceptance Criteria program element is acceptable.

RAI B.1.24-3

Operating Experience. Section B.1.24 of the LRA states that the volumetric inspections have been performed with inservice inspection techniques that have been proven effective within the industry at detecting cracking. The applicant did not provide plant-specific or industry experience for volumetric or visual examination of pressurizer cladding and spray head components from the activities related to its Pressurizer Examinations Program for CNP. The staff addressed this issue in RAI B.1.24-3. The applicant responded in the letter dated August 19, 2004 that WCAP-14574-A and its associated safety evaluation (SE) documented that volumetric examination had been used to support the acceptable disposition of pressurizer cladding cracking at the Haddam Neck Plant. It further stated that volumetric examinations of essentially 100 percent of the circumferential shell-to-head weld (Examination Category B-B) and the weld between the surge nozzle and the pressurizer vessel lower head (Examination Category B-D) performed each inspection interval in accordance with ASME Code, Section XI, provide monitoring for cracking of the cladding that may extend into the underlying base metal. A complete pressurizer inspection history for CNP was provided in the applicant's response to Bulletin 2004-01 dated July 26, 2004, which is under staff review. Since the applicant has reported the plant-specific pressurizer inspection history and industry effort in detecting, sizing, and disposition of cracking in the pressurizer cladding, which is a rare event and is one of the degradation issues discussed in WCAP-14574-A, RAI B.1.24-3 is closed.

UFSAR Supplement

In Section A.2.1.27 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Pressurizer Examinations Program and stated that the program manages cracking of the pressurizer cladding (and items attached to the cladding) that may propagate into the underlying ferritic steel. This program will also determine the condition of the internal spray head, spray head locking bar, and coupling by a one-time visual examination of these components in one CNP unit. This program requires enhancements that will be implemented before the period of extended operation.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.10 Preventive Maintenance

Summary of Technical Information in the Application

Section B.1.25, "Preventive Maintenance," of the LRA describes the applicant's Preventive Maintenance Program. In the LRA, the applicant credited this plant-specific program with maintaining plant SSCs at the quality level required for the safe and reliable operation of the plant. The GALL Report has no comparable program. The program comprises those preventive maintenance tasks that are intended to sustain plant equipment within design parameters and maintain the equipment's intrinsic reliability.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.25 of Appendix B to the LRA regarding the applicant's demonstration of the Preventive Maintenance Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Preventive Maintenance Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that this program element encompasses those tasks credited with managing the aging effects identified in the LRA. The applicant described the SC-specific preventive maintenance activities credited for license renewal under the Detection of Aging Effects program element.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the program element under which the specific components for which the program manages aging are discussed. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that the inspection and testing activities used to identify component aging effects do not prevent aging effects. However, implementation of these activities enables the inspectors to detect aging effects and allow for corrective actions before loss of intended function.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The periodic surveillance and Preventive Maintenance Program activities will identify component aging effects and prevent failures of components that might be caused by aging effects. On this basis, the staff finds that the Preventive Action program element is acceptable.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that the program documents and specific preventive maintenance procedures address parameters such as surface condition, cracking, and other indications of aging effects. Inspection and testing activities monitor various parameters, including surface condition, presence of corrosion products, and signs of cracking.

The staff confirmed that this program element satisfies the criteria defined in Appendix A to the SRP-LR. On the basis of interviews with the applicant's technical staff, the staff finds the applicant's Parameters Monitored or Inspected program element to be acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that preventive maintenance activities provide for periodic component inspections and testing to detect aging effects. Inspection intervals are established such that they provide for the timely detection of degradation. Inspection intervals depend on the component material and environment and take into consideration industry and plant-specific operating experience and manufacturer's recommendations.

The extent and schedule of inspections and testing assure detection of component degradation before the loss of intended functions. The program uses established techniques, such as visual inspections.

The program includes inspections of the centrifugal charging pump casing cladding, as identified in NRC IN 80-38, "Cracking in Charging Pump Casing Cladding," to manage the component-specific aging effect of cladding cracking caused by high localized stresses. After locations of rust or boric acid deposits are mapped, liquid penetrant examinations are used to identify indications of aging. Damaged areas are excavated and reclad with stainless steel. Base metal is repaired if necessary.

Numerous EDG components are inspected in a general fashion, rather than component-by-component listings. This program currently ensures that loss of material, cracking, fouling, and change in material properties are managed for EDG subsystem components. The applicant will enhance the program to manage the aging effects of cracking and change of material properties for the emergency diesel engine elastomer flex hoses or tubing, using visual inspection and replacement as needed. The staff addressed the methods used to monitor a change of material properties of elastomers in flex hoses or tubing associated with the EDG system components in RAI 3.3.3-2, which is discussed in Section 3.3.2.3.8 of this SER.

The program currently performs inspections of control room ventilation air handler unit components, AFW pump room cooling unit components, and the EDG ventilation system. The applicant will enhance the tasks for the control room ventilation air handler packages to include inspection of the heat exchanger tubes and flex joints. These inspections will ensure that loss of material and fouling are managed for the stainless steel heat exchanger tubes, and that changes in material properties and cracking are managed for the elastomer flex joints. The applicant will enhance the tasks for the AFW pump room cooling unit components to include inspection of the internal evaporator tubes, valves, and tubing. These inspections will ensure that loss of material and fouling are managed for the copper alloy components within these units. The applicant will enhance the tasks for the EDG ventilation system to include inspection of the flex joints. These inspections will ensure that changes in material properties and cracking are managed for the elastomer flex joints.

In addition, the applicant will enhance the fire protection system preventive maintenance activities to perform inspections of RCP lubricating oil leakage collection components. The applicant will replace any damaged components that are found to ensure that loss of material is managed and that the intended function of pressure boundary is maintained for the period of extended operation.

The applicant will enhance the program to manage cracking and change in material properties for the rubber hoses in the CA system that require an AMR. This activity will include visual inspection and replacement as needed. The applicant will also enhance the program to manage cracking and change of material properties for the rubber hoses for the postaccident containment hydrogen monitoring system (PACHMS) reagent gas supply. This will include visual inspection and replacement as needed. The applicant will enhance the program to manage cracking and change of material properties for the security diesel engine elastomer flex hoses or tubing, including visual inspection and replacement as needed. The program will also be enhanced to manage cracking and change in material properties of the AFW system elastomer CST floating head seals, including visual inspection and replacement as needed.

Finally, the applicant will specify acceptance criteria and corrective actions as needed for the enhancements. The enhancements are cited in Commitment #16 in Appendix A of this SER.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The measurements and inspections use a frequency and sample size based on operating experience to detect the presence and extent of aging effects. On this basis, the staff finds that the Detection of Aging Effects program element is acceptable.

<u>Monitoring and Trending</u>. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that administrative controls reference activities for monitoring systems and components to permit early detection of degradation. These activities include visual examinations for corrosion, cracking, fouling, leaking and physical condition, mechanical damage, and loose or missing hardware, as appropriate.

The CNP's Corrective Action Program is applicable to this program. This provides reasonable assurance that the applicant will identify trends entailing repeat failures to meet the acceptance criteria and address them with appropriate corrective actions.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before a loss of intended function occurs. On the basis of its review of the Monitoring and Trending program element, the staff finds it acceptable.

<u>Acceptance Criteria</u>. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that specific inspection and testing procedures define the program acceptance criteria. The acceptance criteria confirm component integrity by verifying the absence of aging effects or by comparing applicable parameters to limits based on the relevant intended functions established by the plant design basis. The applicant's Corrective Action Program addresses unacceptable indications of aging effects.

The staff confirmed that this program element satisfies the criteria defined in Appendix A to the SRP-LR. The staff reviewed a selection of the repetitive tasks and associated procedures. In all cases where an aging effect had been identified, appropriate acceptance criteria were provided. Therefore, the staff finds the Acceptance Criteria program element to be acceptable.

Operating Experience. The applicant stated, in Section B.1.25 of Appendix B to the LRA, that the review of operating experience included CRs, program health reports, assessment reports, NRC inspection reports, and LERs.

The applicant stated in the LRA that it overhauled the program as part of the 1997–2000 plant restart effort. Program improvements incorporated proven industry practices and addressed self-identified issues. In 1999, the applicant benchmarked the Preventive Maintenance Program using programs considered to be among the best in the industry. The NRC conducted a special inspection in 1999 and concluded that the preventive maintenance activities were adequate to support restart of the plant. The applicant also stated that to maintain the program, the preventive maintenance group reviews industry operating experience via the Corrective Action Program and factors it into existing or new preventive maintenance tasks, when applicable.

The staff noted that plant operating experience with respect to the Preventive Maintenance Program is extensive. The applicant did not document operating experience for the Preventive Maintenance Program that is specific to the aging effects of concern or the components addressed; however, the staff concluded that the use of the Corrective Action Program and reviews of industry experience are a satisfactory method for ensuring that operating experience is factored into the program appropriately.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Preventive Maintenance Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.28 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Preventive Maintenance Program and stated that the program comprises those preventive maintenance tasks which are intended to sustain plant equipment within design parameters and maintain the equipment's intrinsic reliability. Preventive maintenance activities will provide for periodic component inspections and testing to detect the various aging effects applicable to those components included in the scope of the AMP for license renewal. The applicant stated that it will implement the required program enhancements before the period of extended operation.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.11 Structures Monitoring—Divider Barrier Seal Inspection

Summary of Technical Information in the Application

Section B.1.34, "Structures Monitoring—Divider Barrier Seal Inspection," of the LRA describes the applicant's Structures Monitoring—Divider Barrier Seal Inspection Program. In the LRA, the applicant stated that this is a plant-specific program. The divider barrier in each containment is the physical boundary that separates upper containment from lower containment. Several containment internal structures constitute the divider barrier. Elastomeric seals are provided for penetrations and openings through the divider barrier where it is necessary to limit potential ice condenser bypass leakage subsequent to a postulated pipe rupture or loss of coolant accident. Cracking and change in material properties are AERMs for the pressure seals.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.34 of Appendix B to the LRA, regarding the applicant's demonstration of the Structures Monitoring—Divider Barrier Seal Inspection Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Structures Monitoring—Divider Barrier Seal Inspection Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on how the program manages aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, described in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs describe the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that this program covers the containment divider barrier elastomeric pressure seals around penetrations and openings through the divider barrier.

The staff confirmed that the applicant identified the specific components for which the program manages aging effects, which satisfies the criteria defined in Appendix A.1 to the SRP-LR. On this basis, the staff finds that the applicant's proposed scope is acceptable.

Preventive Actions. In Section B.1.34 of Appendix B to the LRA, the applicant stated that the Structures Monitoring—Divider Barrier Seal Inspection Program is an inspection program. It will involve no actions to prevent or mitigate aging degradation.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for CNP AMP B.1.34 because it is an inspection program.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that this program monitors cracking and change in the material properties of elastomeric pressure seals.

The staff reviewed this program element against the criteria defined in Appendix A to the SRP-LR. The staff reviewed the applicant's procedures which address inspection and testing and describe the parameters for cracking and other geometric discontinuities. The staff did not identify any test or inspection that would reveal a change in material properties.

RAI B.1.34-1

During the AMP audit, the staff requested clarification on the method used to monitor a change in material properties of the elastomeric pressure seals. By letter dated April 23, 2004, the applicant responded that it intended the phrase "change in material properties" to convey a visual inspection to ensure the absence of apparent deterioration (*i.e.*, cracks or defects in the sealing surfaces) as discussed in the implementing procedures. Changes in other material properties are neither monitored nor inspected.

Since cracking is addressed separately and because material properties that may affect the performance of seals (*i.e.*, hardening and embrittlement) are not addressed, the staff did not consider this issue resolved. By letter dated August 20, 2004, in RAI B.1.34-1, the staff asked that the applicant provide a basis for concluding that the elastomeric divider barrier will continue to perform its design function despite changes in material properties that may not be visible. The staff had clarified, in an earlier telephone conversation with the applicant, that the elastomeric pressure seals in question are the penetration seals installed around containment penetrations and openings through the divider barrier. The applicant had stated that the main divider barrier seals are inspected and replaced based on their condition, in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.9, and are not subject to an AMR. Additionally, the applicant noted that the divider barrier personnel access door and equipment hatch seals are visually inspected before containment closure during each outage, in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.5, and are also not subject to an AMR.

By letter dated September 2, 2004, in its response to RAI B.1.34-1, the applicant stated that LRA Table 3.5.2-1, page 3.5.2-1, identifies the divider barrier penetration seals under the component type "removable gate (bulkhead) seals." Table 3.5.2-5, page 3.5-66 of the LRA, identifies this under the component type "divider barrier penetration seals." These elastomeric seals are subject to cracking and change in material properties aging effects and result in thermal exposure and ionizing radiation aging mechanisms. Visual inspection readily identifies the noteworthy effects of these aging mechanisms of elongation, cracking, swelling, and melting. Therefore, the applicant stated that visual inspections would observe these effects as abnormalities indicative of material degradation before aging would challenge the intended function of the seals.

On the basis of its review of the response to RAI B.1.34-1, the staff finds that the applicant's response is acceptable because visual inspection will adequately monitor change in the material properties of the penetration divider barrier seals so that the intended functions of SCs will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, the staff finds that the issue is resolved and that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR.

Detection of Aging Effects. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that the program detects cracking and change in material properties before loss of the pressure seals' intended functions. The seals around penetrations and openings (including the bulkhead gate) are visually inspected to ensure the absence of apparent deterioration (cracks or defects), and the frequency of inspection is at least once every 10 years.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will inspect the divider barrier seals at least once every 10 years. Visual inspections will examine the pressure seals for signs of cracking or surface defects properties before the loss of intended function.

Monitoring and Trending. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that this program monitors aging effects through visual examination of the seals. The Corrective Action Program provides reasonable assurance that the applicant will identify repeated failures to meet acceptance criteria and addressed them with appropriate corrective actions.

The staff confirms that, for visual inspection, this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The plant procedures describe the documentation and monitoring of visual inspection results.

Acceptance Criteria. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that seals must be free of unacceptable deterioration (excessive cracks or defects) and unacceptable misalignment.

The staff reviewed this program element to determine if it satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will consider any degradation that could lead to a loss of function to be unacceptable and implement corrective measures.

RAI B.1.34-2

The acceptance criteria described in implementing procedures include evidence of chemical attack, radiation damage, or changes in physical appearance. The applicant did not provide any guidance as to how it would evaluate these effects.

By letter dated August 20, 2004, in RAI B.1.34-2, the staff requested clarification on the acceptance criteria for evaluating changes in material properties of elastomers, specifically, the pressure seals (divider barrier). The staff determined that implementing procedures mention evidence of chemical attack, radiation damage, or changes in physical appearance. The staff asked the applicant to clarify how it will evaluate these and confirm that visual evidence of degradation will precede a loss of function.

By letter dated September 2, 2004, in its response to RAI B.1.34-2, the applicant stated that the acceptance criteria for these elastomers include the absence of elastomeric seal material abnormalities, such as swelling, surface cracking, discoloration, surface peeling, separation, melting, holes, ruptures, abrasions, or other changes in appearance. The applicant stated that it will evaluate any abnormality and degradation under the Corrective Action Program to ensure that the pressure boundary function of the degraded seal is intact.

On the basis of its review of the applicant's response to RAI B.1.34-2, the staff finds it acceptable because visual inspection of the elastomeric seals will detect degradation before the loss of intended function. The staff concludes that the applicant has satisfied the acceptance criteria defined in Appendix A.1 to the SRP-LR.

Operating Experience. The applicant stated, in Section B.1.34 of Appendix B to the LRA, that its operating experience relative to the Structures Monitoring—Divider Barrier Seal Inspection Program includes CRs and LERs. The review revealed that the program monitors and detects the aging of the elastomer seals before loss of intended function occurs. The CRs include all aspects of the divider barrier seal and indicate no pattern of repeat conditions. For example, a CR documented the adequacy of inspection and replacement criteria for seals covered by the program. Another CR and associated LERs document the correction of ice condenser bypass leakage in excess of the design basis through the implementation of design changes.

The applicant also stated that the limited number of ice condenser containments has resulted in minimal industry operating experience. The applicant did not identify any examples of industry experience relative to the CNP plants.

The staff reviewed one of the applicant CRs which describes operating experience from the existing barrier seal inspection and monitoring program. The staff recognizes that the Corrective Action Program, which captures internal and external plant operating experience issues, will provide reasonable assurance that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

On the basis of its review and discussions with the applicant's technical staff, the staff concludes that the Structures Monitoring—Divider Barrier Seal Inspection Program will adequately manage the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.37 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Structures Monitoring—Divider Barrier Seal Inspection Program. The program detects cracking and change in material properties of elastomeric pressure seals for penetrations and openings through the containment divider barrier. The program detects aging effects through visual examination of the seals.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.12 Structures Monitoring—Ice Basket Inspection

Summary of Technical Information in the Application

Section B.1.35, "Structures Monitoring—Ice Basket Inspection," of the LRA describes the applicant's Structures Monitoring—Ice Basket Inspection Program. The GALL Report has no comparable program. In the LRA, the applicant credited this plant-specific program with providing instructions to verify that ice condenser baskets are free of detrimental structural wear, cracks, corrosion, or any other noticeable damage. The functional integrity of the ice condenser baskets ensures that the ice condenser can perform its intended safety function.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.35 of Appendix B to the LRA, regarding the applicant's demonstration of the Structures Monitoring—Ice Basket Inspection Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Structures Monitoring—Ice Basket Inspection Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that the program verifies that the ice condenser baskets are operable. Technical specifications mandate periodic checking of a sample of ice baskets to verify that they are free of detrimental structural wear, cracks, corrosion, or other damage.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that the Structures Monitoring—Ice Basket Inspection Program is an inspection program. It will involve no actions to prevent or mitigate aging degradation.

The staff confirmed that the program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for the Structures Monitoring—Ice Basket Inspection Program because it is a condition monitoring program.

Parameters Monitored or Inspected The applicant stated, in Section B.1.35 of Appendix B to the LRA, that visual checks are made for the ice basket bottom, top rim, coupling connections, stiffener rings, weld seams, and ligaments. Ligaments are checked for visible pitting or surface metal wastage caused by corrosion that is significant enough to dimensionally affect the ligament.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The Structures Monitoring—Ice Basket Inspection Program activities detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that the program detects loss of material of the ice baskets before loss of structure and component intended function.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The inspections are conducted, using a frequency and sample size required by plant technical specifications, to detect the presence and extent of aging effects. On that basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that results of the ice basket inspections are retained to permit confirmation of the inspection program effectiveness.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that plant procedures specify the acceptance criteria for the ice basket inspections to ensure that the ice baskets are free of detrimental structural wear, cracks, corrosion, or other damage.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant will consider any identified deficiencies to be unacceptable and implement corrective measures. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience. The applicant stated, in Section B.1.35 of Appendix B to the LRA, that its review of relevant operating experience included CRs, LERs, and NRC inspection reports.

The applicant stated in the LRA that the CRs related to this program identify ice basket damage and flow passage problems, among others. The applicant found the damage to baskets to result from improper handling of the baskets during testing (weighing) and refilling, rather than aging effects. The applicant also stated that it incorporated enhancements into the program under the corrective actions for these CRs. The NRC inspected the ice condensers in 1998 and did not identify any aging effects in the inspection report.

The staff reviewed the applicant's procedure associated with the Structures Monitoring—Ice Basket Inspection Program, which provides enhanced instructions for maintaining ice baskets. The applicant made additional program enhancements under the Corrective Action Program. Based on its review, the staff concludes that the applicant has identified operating experience for the Structures Monitoring—Ice Basket Inspection Program and performed corrective actions, where needed, as a result.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that CNP AMP B.1.35 adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.38 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Structures Monitoring—Ice Basket Inspection Program and stated that the program verifies that ice condenser baskets are free of detrimental structural wear, cracks, corrosion, or noticeable damage. The program detects loss of material of the ice baskets by visual inspections, as required by technical specifications.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.13 System Testing

Summary of Technical Information in the Application

Section B.1.37, "System Testing," of the LRA describes the applicant's System Testing Program. The GALL Report has no comparable program. In the LRA, the applicant credited this plant-specific program with encompassing a number of miscellaneous system and component testing activities that manage the effects of aging. These activities typically include surveillance activities required by the applicant's technical specifications or normal monitoring of plant operation (*i.e.*, plant log readings or other normal monitoring techniques). In general, the applicant conducts these activities on a periodic basis (surveillances) or routinely (logs) during plant operation. The activities verify the continuing capability of safety-related systems and components to meet established performance requirements.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.37 of Appendix B to the LRA regarding the applicant's demonstration of the System Testing Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the System Testing Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that the scope of the program includes (1) the centrifugal charging pump test, (2) ESF ventilation units testing, (3) control room ventilation units testing, (4) fuel handling area exhaust unit testing, (5) the security diesel test, (6) the letdown orifice test, (7) main steamflow meter monitoring, (8) blowdown system normal operation monitoring, and (9) SFP water level monitoring.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that the System Testing Program is a monitoring program and will involve no actions to prevent or mitigate aging degradation.

The staff confirmed that the program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for CNP AMP B.1.37 because it is a condition monitoring program.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that the program monitors flow rates and pressure.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The program monitors such aging effects as the loss of material in the centrifugal charging pump discharge orifice and aging effects on drains from various ventilation units. It addresses fouling and loss of material in parts of the security diesel, as well as loss of material in the buried fuel oil storage tank, pipe, tubing and associated fittings, starting air components, and (diesel) exhaust gas components. In addition, during the course of plant operation, the program monitors the condition of CVCS letdown orifices, blowdown system restricting orifices, and main steam system flow restrictors, as well as the level of the SFP. The Site Surveillance Tracking Database maintains frequencies for monitoring parameters evaluated by the System Testing Program. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that it will enhance system testing of the centrifugal charging pumps to manage the loss of material for the centrifugal charging pumps minimum flow orifices and the Unit 1 centrifugal charging pumps discharge orifices. ASME Code, Section XI, pump testing will verify that the orifices have not experienced loss of material to the extent of impacting the ability of a pump to provide the required flow.

The applicant will enhance system testing of the ESF ventilation units to manage the effects of aging on the drain valves and drain piping from these units. During surveillance testing, a visual inspection of the drain valves and drain piping will be accomplished.

The applicant will enhance system testing of the control room ventilation units and fuel handling exhaust unit to manage the effects of aging on the drain valves and drain piping from these units. During surveillance testing, a visual inspection of the drain valves and drain piping will be accomplished.

Testing requirements include periodically starting the security diesel and operating it in accordance with the manufacturer's recommendations. The applicant credited system testing with managing fouling and the loss of material for the security diesel jacket water heat exchangers and lubricating oil heat exchanger tubes. Since periodic engine testing and inspections are performed on the security diesel, system testing is also credited for managing the loss of material for the buried fuel oil storage tank, pipe, tubing and fittings, starting air components, and exhaust gas components. Fuel oil level indication and periodic pressure testing with use of the spectacle flange manage the aging effects on the buried fuel oil storage tank. During engine operation, monitoring engine parameters and performing visual inspections manage the aging effects by verifying the pressure boundary of engine components. In addition, the applicant performs 6-month and annual inspections on the security diesel to manage the aging effects on security diesel passive mechanical components.

The letdown orifices reduce the pressure in the letdown line from RCS pressure to the lower pressure allowed for the demineralizers and other CVCS components. Normal plant operation will verify the ability of the letdown orifices to control flow. The applicant records CVCS letdown flow continuously on the plant process computer.

System testing includes monitoring the components during normal plant operation. For the main steam system, this monitoring manages the aging effect of loss of material from the main steamflow restrictors. Changes in the flow reading would detect a material loss from the internal surface of the flow restrictors significant enough to impact its flow control function. For the blowdown system, the applicant credited this monitoring with ensuring that the restricting orifices perform their flow control (pressure breakdown) function and manage the aging effect of loss of material from erosion for the internal surfaces of the orifices.

Finally, the applicant monitors the SFP water level and records it once per shift. Monitoring the SFP level allows early detection of leakage through the SFP liner. This program manages the aging effect of loss of material and cracking for the SFP liner.

By letter dated May 6, 2004, the staff forwarded to the applicant an RAI stating that, in LRA Table 3.3.2-9, the applicant credited the System Testing Program with managing loss of material for stainless steel fittings and stainless steel/carbon steel piping in a soil environment. However, the System Testing Program does not define fitting or pipe condition, or the approximate rate of degradation as recommended in GALL AMPs XI.M28, "Buried Piping and Tanks Surveillance," and XI.M34, "Buried Piping and Tanks Inspection," for buried fittings/piping. Therefore, in RAI 3.3.2.1.9-1 the staff asked the applicant to either justify the exclusion of the buried piping/fittings condition assessment from the System Testing Program or to revise its LRA accordingly (see Section 3.3.2.3.9 of this SER for the response to and staff evaluation of RAI 3.3.2.1.9-1).

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The selection of parameters monitored and the frequency with which they are evaluated are consistent with the goal of detecting aging effects before loss of function occurs. The applicant identified the need to enhance the System Testing Program to inspect centrifugal charging pump minimum flow orifices and to address the verification of pressure boundary integrity in various drain systems. The staff finds that the Detection of Aging Effects program element is acceptable.

<u>Monitoring and Trending</u>. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that it performs the surveillance and monitoring activities associated with this program on a specific frequency, as listed in the Site Surveillance Tracking Database, and documents the results of these activities. The program includes various frequencies, depending upon the specific component or system tested.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before a loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

<u>Acceptance Criteria</u>. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that the governing procedures provide the acceptance criteria and guidelines for the surveillances and normal log readings. Acceptance criteria are tailored for each individual system or component test.

The staff reviewed a sample of plant testing procedures and confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that, under the plant Corrective Action Program, the applicant will find deficiencies unacceptable, when discovered during inspections, and implement corrective measures. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

<u>Operating Experience</u>. The applicant stated, in Section B.1.37 of Appendix B to the LRA, that a review of CRs and interviews with the system managers, related to the various tests and inspections that constitute the System Testing Program, found that testing procedure issues

have been identified and corrected. Although typical component problems have been identified, system testing has not identified aging-related problems for monitored components.

The staff noted that plant operating experience with respect to system testing is extensive. The staff reviewed the applicant's documentation of operating experience for the System Testing Program and finds that it is not specific to the aging effects of concern or the components addressed. However, the program has identified and corrected comparable component problems, suggesting that it will be effective if aging effects are observed.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the System Testing Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.40 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the System Testing Program and stated that the program encompasses a number of miscellaneous system and component testing activities credited for managing the effects of aging. These activities typically include surveillance activities required by the technical specifications or normal monitoring of plant operation (*i.e.*, plant log readings or other normal monitoring techniques). In general, the applicant conducts these activities on a periodic basis (surveillances) or routinely (logs) during plant operation. The activities verify the continuing capability of safety-related systems and components to meet established performance requirements. This program requires enhancements that will be implemented before the period of extended operation. The enhancements are part of Commitment #26 in Appendix A of this SER.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.14 System Walkdown

Summary of Technical Information in the Application

Section B.1.38, "System Walkdown," of the LRA describes the applicant's System Walkdown Program. In the LRA, the applicant credited this plant-specific program with (1) managing the loss of material from internal surfaces for situations in which the external surface condition is representative of the internal surface condition and both have the same environment, (2) managing loss of material of external carbon steel surfaces, and (3) managing loss of mechanical closure integrity for bolted closures that may be exposed to borated water leakage. The applicant also credited the program with detecting leakage and spray from liquid-filled low-energy systems before such leakage can prevent the satisfactory accomplishment of safety functions.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.38 of Appendix B to the LRA, regarding the applicant's demonstration of the System Walkdown Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the System Walkdown Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that, it will enhance this program element to include balance-of-plant systems such as fire protection and security diesel and nonsafety-related components affecting safety-related systems.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that for carbon steel components with coatings, the System Walkdown Program manages the loss of material due to corrosion of the carbon steel surfaces by ensuring that the coating integrity is maintained.

The staff confirmed that the program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The System Walkdown Program activities will identify component aging effect and prevent failures of components that might be caused by aging effects. On this basis, the staff finds that the Preventive Actions program element is acceptable.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that during a walkdown, the engineer monitors for items which could affect system performance, safety, or reliability, as well as general housekeeping, personnel safety hazards, and radiological concerns. Examples of parameters inspected during the system walkdowns include condition and placement of coatings, evidence of corrosion, and indications of leakage. The applicant also stated that it will enhance this program element to ensure that evidence of corrosion is adequately monitored.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The system walkdown activities are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that it conducts a general visual inspection on readily accessible system and component surfaces during walkdowns. It credited the program with managing the loss of material for external and internal carbon steel surfaces, loss of mechanical closure integrity for bolted closures that may be exposed to borated water leakage, loss of material (including that caused by selective leaching) for copper alloy and cast iron surfaces, and cracking of stainless steel surfaces.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant conducts walkdowns, using a frequency and sample size based on operating experience, to detect the presence and extent of aging effects. By letter dated May 26, 2004, in related RAI 3.3.2.1.11-3, the staff asked the applicant to explain how the System Walkdown Program will detect the loss of material on the internal surfaces of the components subject to an AMR that meet the criterion of 10 CFR 54.4(a)(2), or on those nonsafety related components that affect the safety related function of a system within the scope of license renewal (see Section 3.3.2.3.11 of this SER for the response to and staff evaluation of RAI 3.3.2.1.11-3). The staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that quarterly walkdown reports document the observations.

During the audit, the staff asked whether the walkdowns are performed quarterly or merely documented quarterly. The applicant responded that it performs the walkdowns quarterly and provided documentation of this requirement.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The respective plant system managers define the scope of the walkdowns. The program requires written reports, and the Corrective Action Program documents discrepancies. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that walkdown reports document safety or operability concerns and provide an overall assessment of the system condition, based on observations. The reports summarize specific needs for improvement and followup actions. CRs are generated, as required. The applicant also stated that it will enhance this program element to ensure the adequate detection of aging effects.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that the applicant will consider any deficiencies to be unacceptable and implement corrective measures. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience. The applicant stated, in Section B.1.38 of Appendix B to the LRA, that CRs document indications of component aging identified during system walkdowns.

Walkdowns have identified conditions such as boric acid leakage at a valve flange, corrosion on anchor bolts, and tank surface pitting.

The applicant stated in the LRA that the CRs show that not only have aging effects like corrosion been noted and corrected, but aging management conditions that promote these aging effects have been noted and corrected as well. Among the conditions noted during a walkdown of the control room ventilation system in 1999, corrosion of the inside of the duct work was believed to be caused by clogged drains, which was in turn caused by inadequate surveillance activities and insufficient housekeeping. The control room ventilation system was cleaned monthly for 6 months until the condition of the system was such that a return to normal housekeeping was considered adequate.

The staff reviewed the applicant's documents and concludes that the applicant has identified operating experience for the System Walkdown Program and performed corrective actions, where needed, as a result.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the System Walkdown Program adequately manages the aging effects that have been observed at the applicant's plant.

<u>UFSAR Supplement</u>

In Section A.2.1.41 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the System Walkdown Program and stated that the program conducts inspections to manage the loss of material, the loss of mechanical closure integrity, and cracking, as applicable, for SCs within the scope of license renewal. The program uses general visual inspections of readily accessible system and component surfaces during system walkdowns. The applicant stated that it will implement the required program enhancements before the period of extended operation. The enhancements are part of Commitment #27 in Appendix A of this SER.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

<u>Conclusion</u>

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.15 Wall Thinning Monitoring

Summary of Technical Information in the Application

Section B.1.39, "Wall Thinning Monitoring," of the LRA describes the applicant's Wall Thinning Monitoring Program. In the LRA, the applicant credited this new, plant-specific program with managing the aging effects for loss of material to ensure that wall thickness is above the minimum required in order to avoid failures under normal, transient, and accident conditions, including seismic events.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.39 of Appendix B to the LRA, regarding the applicant's demonstration of the Wall Thinning Monitoring Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Wall Thinning Monitoring Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that the program encompasses wall thinning monitoring inspections for carbon steel piping and valves in the containment isolation system and AFW system to ensure that piping wall thickness is above the minimum required.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that the Wall Thinning Monitoring Program is an inspection program and will include no actions to prevent or mitigate degradation caused by aging.

The staff confirmed that the program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff did not identify the need for preventive actions for the Wall Thinning Monitoring Program because it is a condition monitoring program.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that it will perform nondestructive examinations on susceptible components to determine wall thickness.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The Parameters Monitored or Inspected program element is acceptable because the measurements of wall thickness are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that this program manages the aging effect of loss of material. The applicant will determine an appropriate sample size based on operating experience before these inspection activities occur. It will design the extent and schedule of the examinations prescribed by the program to ensure that aging effects will be discovered and repaired before the loss of intended function. Inspections will be performed periodically at a frequency to be determined before implementation. The frequency of inspections will depend upon results of previous inspections, the calculated rate of material loss, and industry and plant operating experience. In addition, the applicant credited this program with managing the aging effects of loss of material from the internal surfaces of the containment penetrations' carbon steel components and loss of material on the internal surfaces of the AFW system carbon steel components.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The applicant stated that it will perform the inspections periodically at a frequency to be determined before the end of the initial 40-year license term. The frequency of inspections will depend upon the results of previous inspections, the calculated rate of material loss, and industry and plant operating experience. On this basis, the staff finds the Detection of Aging Effects program element to be acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that it will trend wall thickness and project it to the next inspection. It will take corrective actions if the projections indicate that the acceptance criteria may not be met at the next inspection.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before the loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that wall thickness measurements greater than minimum wall thickness values for the components' design code of record will be acceptable.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that the applicant will consider any wall thickness values that are projected to fall below the design code minimum to be unacceptable and implement corrective measures. The staff concludes that this acceptance criterion is adequate to demonstrate that a loss of material because of wall thinning will be managed for the period of extended operation and that correction actions will be implemented for any wall thickness values projected to fall below the minimum allowable. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience. The applicant stated, in Section B.1.39 of Appendix B to the LRA, that the Wall Thinning Monitoring Program is a new program for which there is no operating experience. It will consider industry and plant-operating experience in the development of this program.

The Operating Experience program element criteria in Appendix A.1 to the SRP-LR states that operating experience should provide objective evidence to support the conclusion that the program will adequately manage the effects of aging so that the SC intended functions will be maintained during the period of extended operation.

The staff observed that ultrasonic wall thickness examinations are consistent with industry standards, and the applicant indicated that if initial or periodic examinations reveal the need to expand the sample size or increase the frequency of these activities, such actions would occur. The operating experience associated with this AMP will be accrued over the period of extended operation.

During the audit, the staff asked the applicant to clarify and/or provide the operating experience reviews for new programs. In its response, the applicant stated that the plant Corrective Action Program, which captures internal and external plant operating experience issues, provides reasonable assurance that operating experience will be reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging will be adequately managed.

On the basis of its review and discussions with the applicant's technical staff, the staff concludes that the Wall Thinning Monitoring Program will adequately manage the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.42 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the *Wall Thinning Monitoring Program and stated that the program will manage the loss of* material of carbon steel piping and valves in the containment isolation and AFW systems. The applicant will perform inspections to ensure that wall thickness is above the minimum required in order to avoid failures. Finally, the applicant will implement the Wall Thinning Monitoring Program before the period of extended operation. This is Commitment #28 in Appendix A of this SER.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.16 Water Chemistry Control—Auxiliary Systems Water Chemistry Control

Summary of Technical Information in the Application

Section B.1.40.3, "Water Chemistry Control—Auxiliary Systems Water Chemistry Control," of the LRA describes the applicant's Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program. In the LRA, the applicant credited this plant-specific program with managing the loss of material, cracking, and fouling of components exposed to treated water environments.

Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section B.1.40.3 of Appendix B to the LRA, regarding the applicant's demonstration of the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program to ensure that it will adequately manage the effects of aging, as discussed above, so that the intended functions of SCs will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program against the AMP elements found in Table A.1-1 and Section A.1.2.3 of Appendix A to the SRP-LR and focused on the program's management of aging effects through the effective incorporation of the 10 program elements.

The applicant indicated that the site-controlled Quality Assurance Program, evaluated in Section 3.0.4 of this SER, includes the corrective actions, confirmation process, and administrative controls. The following paragraphs discuss the remaining seven elements.

Scope of Program. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that the program encompasses sampling activities and analyses of the demineralized water supply penetrations and nonsafety-related components affecting safety-related systems, control room ventilation liquid chiller components, glycol/ice condenser penetrations, glycol/ice condenser nonsafety-related components affecting safety-related systems, primary water supply to pressurizer relief tank penetrations, primary water system nonsafety-related components affecting safety-related systems, EDG jacket cooling water, and security diesel jacket cooling water.

The staff confirmed that the Scope of Program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff finds that the applicant's proposed program scope is acceptable.

Preventive Actions. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that this program monitors and controls relevant conditions such as dissolved oxygen, conductivity, and corrosion inhibitor concentrations to manage loss of material and fouling, as applicable. These corrosive contaminants are either removed, their concentrations minimized, or treatments are provided to limit their corrosive effects.

During the audit, the applicant provided clarification on the parameters to be monitored and their ability prevent or mitigate the aging effects. Where applicable, system chemistry monitoring uses the principles for chemical treatment and a typical (chemistry) monitoring program presented in EPRI TR-107396. Dissolved oxygen is included as a diagnostic parameter because it can increase corrosion. The demineralized water application includes it as a control treatment parameter. Conductivity is included as a diagnostic parameter because it is an indirect measurement of the concentration of chemical treatment (used to minimize corrosion or fouling). Corrosion inhibitor is monitored for direct measurement of the treatment control concentration used for corrosion control. Because pH has a direct impact on corrosion rate and might be an indicator of microbiological activity in the system, it is included as a treatment control parameter. Iron and copper are included as diagnostic parameters because accumulation of corrosion products is an indirect indication of corrosion. Hardness is monitored to provide indication of the formation of mineral scales. Nitrate is monitored and included as a diagnostic for an indication of an increase in microbiologic activity. Glycol weight percentage concentration is monitored to ensure that the range specified in Section 5.3.5.12.3 of the UFSAR is maintained.

The staff confirmed that the Preventive Actions program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. On the basis of its audit of the implementation procedures and review of the program basis documents, the staff finds that the Preventive Actions program element is acceptable because it identifies and describes the activities for managing aging effects.

Parameters Monitored or Inspected. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that the program monitors specific parameters such as dissolved oxygen, conductivity, and corrosion inhibitor concentrations. It monitors other typical parameters, including pH, iron, copper, hardness, and nitrite. The specific parameters monitored vary depending on the system.

During the audit, the applicant stated that the parameters monitored and the established chemistry limits in the auxiliary cooling systems are based on a strategic plan that was developed according to the systems' materials of construction and currently approved chemical treatments. The program monitors corrosion inhibitor concentrations to ensure adequate protection of the system materials from corrosion. Other parameters are monitored to assess the rates of corrosion and stability of the system. In the case of primary makeup systems, parameters and limits are based on practices developed by EPRI for primary water chemistry.

The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The component inspections and water chemistry monitoring activities are intended to detect the presence and extent of aging effects. On this basis, the staff finds that the Parameters Monitored or Inspected program element is acceptable.

Detection of Aging Effects. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program is a mitigation program and does not provide for detection of aging effects, such as loss of material and cracking. This applicant credited this program with managing the aging effects of the following: loss of material for the demineralized water, glycol/ice condenser, and primary water containment penetrations; loss of material (including that caused by selective leaching) and fouling in the EDG cooling water system; loss of material (including that caused by selective leaching) and fouling from the internal wetted surfaces of the control room ventilation liquid chiller components; loss of material (including that caused by selective leaching) for the security diesel engine cooling water; and loss of material (including that caused by selective leaching) for the demineralized water, ice condenser, and primary water nonsafety-related components affecting safety-related systems.

The staff agrees that this is a mitigation program and as such does not detect aging effects, such as loss of material and cracking. Therefore, the staff concluded that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. On this basis, the staff finds that the Detection of Aging Effects program element is acceptable.

Monitoring and Trending. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that it implements the program through various plant procedures. The applicable procedures identify the sampling schedule, the critical parameters, and the location of the sample points. The applicant monitors the parameters and takes corrective actions if the parameters are outside the acceptable range.

The staff reviewed several implementing procedures and determined that the applicant defined the sampling schedule, critical parameters, and location of the sample points. The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. Trending of the inspection results will enhance the applicant's ability to detect aging effects before loss of intended function occurs. On this basis, the staff finds that the Monitoring and Trending program element is acceptable.

Acceptance Criteria. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that site procedures for this program include the acceptance criteria, which are established based on the sampled parameter, the sample location, and the plant operating conditions. The applicant established these criteria based on equipment specification requirements, EPRI guidelines, or CNP-specific experience.

The staff reviewed several plant procedures and verified that the program includes a methodology for analyzing the results against specific numerical acceptance criteria. The staff confirmed that this program element satisfies the criteria defined in Appendix A.1 to the SRP-LR. The staff finds that the applicant will consider any inspection results that indicate component degradation or any chemistry parameters that fall outside those contained in applicable industry and manufacturers' guidelines and implement corrective measures. On this basis, the staff finds that the Acceptance Criteria program element is acceptable.

Operating Experience. The applicant stated, in Section B.1.40.3 of Appendix B to the LRA, that a review of representative CRs relevant to the program shows that the program identifies out-of-specification values and corrects them before they lead to equipment degradation. For example, the program identified and corrected excessive sodium in the borated water inventories, nitrites below the minimum limit for the diesel jacket cooling water, and low pH in the alternate heating boiler.

During the audit, the staff interviewed applicant personnel concerning the operating experience of this existing program to validate the AMP statements. The plant records confirm that the program has effectively identified water chemistry parameters and taken corrective actions. Based on its review, the staff concludes that the operating experience of this program demonstrates that it is an effective tool for mitigating the aging effects of loss of material and cracking.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff concludes that the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program adequately manages the aging effects that have been observed at the applicant's plant.

UFSAR Supplement

In Section A.2.1.45 of Appendix A to the LRA, the applicant provided the UFSAR Supplement for the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program. It stated that the program manages loss of material and fouling, as applicable, of components within the scope of license renewal that are exposed to treated water environments. The program implements sampling activities and analyses to monitor and control relevant chemistry conditions of these environments.

The staff reviewed the UFSAR Supplement and confirms that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

Conclusion

On the basis of its review and audit of the applicant's program, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions of SCs 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).

3.0.3.3.17 Water Chemistry Control—Chemistry One-Time Inspection

Summary of Technical Information in the Application

Section B.1.41, "Water Chemistry Control—Chemistry One-Time Inspection," of the LRA presents the applicant's program to evaluate the effectiveness of water chemistry programs. The applicant stated that this plant-specific program will be comparable to GALL AMP XI.M32, "One-Time Inspection," and consistent with its general elements, but smaller in scope. The program performs inspections that will verify the effectiveness of water chemistry control programs and ensure that aging effects are effectively managed during the period of extended operation. The applicant stated that qualified personnel will perform combinations of NDE (including visual, ultrasonic, and surface techniques) by following procedures consistent with ASME Code, Section XI, and Appendix B to 10 CFR Part 50. Followup of unacceptable inspection findings may include expansion of the inspection sample size and locations.

Staff Evaluation

The GALL Report recommends use of GALL AMP XI.M32 to verify the effectiveness of an AMP and confirm the absence of an aging effect. For example, for SCs that rely on an AMP such as a water chemistry control program, GALL AMP XI.M32 verifies the effectiveness of the AMP by confirming that unacceptable degradation is not occurring and that the intended function of a component will be maintained during the period of extended operation. One-time inspection addresses cases where either (1) an aging effect is not expected to occur but there are insufficient data to rule it out, or (2) an aging effect is expected to progress very slowly. One-time inspection can provide assurance that aging is either not occurring, or the aging effect is occurring very slowly so as not to affect the intended function of the structure and component. When a one-time inspection reveals evidence of an aging effect, the evaluation of the inspection results would identify appropriate corrective actions, which may include followup inspections.

In a letter dated May 19, 2004, the staff requested in RAI B.1.41-1 that the applicant provide details about key program elements that clarify the difference between the applicant's program and GALL AMP XI.M32. In a letter dated August 11, 2004, the applicant stated that two CNP AMPs contain GALL AMP XI.M32; the Small Bore Piping Program, described in LRA Section B.1.30, and the Water Chemistry Control—Chemistry One-Time Inspection Program, described in LRA Section B.1.41. According to the applicant, these two programs comprise all of the elements of GALL AMP XI.M32, and there are no resultant differences between GALL AMP XI.M32 and the two programs listed in the LRA. The staff concluded that the applicant's Water Chemistry Control—Chemistry One-Time Inspection Program is consistent with the GALL AMP XI.M32 for the components included within its scope, and that the only difference is the use of a separate program to address small bore piping.

The applicant stated that the Water Chemistry control—Chemistry One-Time Inspection Program is a new program that will be developed and initiated prior to the period of extended operation. This is Commitment #30 in Appendix A of this SER. The program will address components for which a water chemistry control programs have been credited as an AMP in the LRA Section 3 AMR results tables. In addition, the program will focus on materials and environments for which the GALL Report specifies the need to verify effectiveness of the water chemistry control programs. The elements of the GALL AMP XI.M32 include (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

The applicant stated that examples include carbon steel components in applicable steam and power conversion systems. The program will include components in stagnant or low-flow areas that are most susceptible to aging. In a public meeting on September 1, 2004, documented as RAI B.1.41-2 in a letter dated September 29, 2004, the staff asked the applicant to provide a list of components, material types, environments, and aging effects that will be inspected to verify the effectiveness of the Water Chemistry Control—Chemistry One-Time Inspection Program and to justify that these components provide an adequate sample size to verify the effectiveness of the program for each aging effect managed.

In a response dated October 18, 2004, the applicant confirmed that its program will include all combinations identified by the GALL Report for the aging management of PWR components using water chemistry control and the One-Time Inspection Program. The staff compared the applicant's AMR with the one-time inspections recommended in the GALL Report to verify the effectiveness of water chemistry control in managing aging. The staff confirmed that these structures and components are either included in the applicant's One-Time Inspection Program or another aging management program that includes periodic inspection (*i.e.*, Diesel Fuel Monitoring Program, Boric Acid Corrosion Prevention Program). For example, the GALL Report recommends water chemistry control and one-time inspection for general, pitting, and crevice corrosion of steam and power conversion system components such as piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head, and shells. The staff confirmed that the applicant's AMR includes these items and identifies water chemistry and one-time inspection as the AMPs.

In the October 18, 2004 letter, the applicant also identified additional material and environment combinations, beyond those listed in the GALL Report, that it will include in the One-Time Inspection Program. Other RAI responses (RAIs 3.2-11, 3.2-12, 3.3.2.1.9-4, 3.3.2.1.9-6, 3.4-7, 3.4-8, 3.4-10, 3.4-11, and 3.3.2.1.11-1) originally documented these combinations. These additional combinations include the loss of material of a copper alloy heat exchanger tubes in treated water; loss of material of carbon steel in treated water and stainless steel in borated water in the ESF system; copper alloy security diesel and jacket water coolers; loss of material and fouling of copper alloy tubes in the AFW system; loss of material and cracking of stainless steel and loss of material of carbon/alloy steel in treated water and steam; and copper alloy, carbon steel, and stainless steel components exposed to raw and untreated water. The staff finds the scope of the program acceptable because it includes the items identified in the GALL Report, as well as additional items for which a one-time inspection is appropriate to verify the effectiveness of water chemistry control.

Regarding the actual sample population and size for the inspections, the applicant stated in the October 18, 2004 response that the list of specific components and locations is not available because the CNP Chemistry One-Time Inspection Program is new. The applicant confirmed that the sample population (and size) will be based on material, environment, time in service, aging effects, and operating experience, as discussed in GALL AMP XI.M32. Also consistent with the GALL Report, the applicant stated in the LRA that qualified personnel will perform combinations of NDE (including visual, ultrasonic, and surface techniques) following procedures consistent with the ASME Code, Section XI and Appendix B to 10 CFR Part 50. Follow-up of unacceptable inspection findings may include expansion of the inspection sample size and locations. When the program details are determined, the acceptance criteria will be specified based on the relevant conditions of degradation. The staff finds these elements of the program acceptable because they are consistent with the GALL Report.

<u>UFSAR Supplement</u>

In Section A.2.1.45 of Appendix A to the LRA, the applicant provided its UFSAR Supplement for the Water Chemistry Control—Chemistry One-Time Inspection Program. The staff reviewed the UFSAR Supplement and finds that the summary description contains a sufficient level of information to satisfy 10 CFR 54.21(d) and therefore is acceptable.

<u>Conclusion</u>

The staff reviewed the available information on the applicant's program and finds that the program is consistent with the GALL Report. Certain details, such as the exact sample size and the inspection method, will be determined in when the plan is implemented. The one difference between this program and the GALL AMP is the exclusion of small bore piping, which is covered by a separate program. 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, based on its review, the staff finds that the applicant has shown that the effects of aging will be adequately managed by the Water Chemistry Control - Chemistry One-Time Inspection program 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).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant must demonstrate that it will adequately manage the effects of aging on SCs subject to an AMR so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The SRP-LR, BTP RLSB-1, "Aging Management Review—Generic," describes 10 attributes of an acceptable AMP. Three of these 10 attributes are associated with the QA activities of corrective action, confirmation processes, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of BTP RLSB-1 provides the following description of these quality attributes:

- Corrective actions, including root cause determination and prevention of recurrence, should be timely.
- The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Administrative controls should provide a formal review and approval process.

The SRP-LR, BTP IQMB-1, "Quality Assurance for Aging Management Programs," notes that those aspects of the AMP that affect the quality of safety-related SSCs are subject to the QA requirements of Appendix B to 10 CFR Part 50. Additionally, for nonsafety-related SCs subject to an AMR, the applicant may use the existing Quality Assurance Program under Appendix B to 10 CFR Part 50 to address the program elements of Corrective Actions, Confirmation Process, and Administrative Controls. BTP IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

- Safety-related SCs are subject to the requirements under Appendix B to 10 CFR Part 50, which adequately address all quality-related aspects of an AMP consistent with the CLB of the facility for the period of extended operation.
- For nonsafety-related SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its Quality Assurance Program under Appendix B to 10 CFR Part 50 to include these SCs to address corrective actions, the confirmation process, and administrative controls for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the FSAR Supplement in accordance with 10 CFR 54.21(d).

3.0.4.1 Summary of Technical Information in the Application

The applicant described the quality attributes of AMPs in Section B.0.3, "CNP Corrective Actions, Confirmation Process, and Administrative Controls," of the LRA.

Corrective Actions The applicant stated that it implements CNP QA procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. Conditions adverse to quality (*i.e.*, failures, malfunctions, deviations, defective material and equipment, and nonconformances) are promptly identified and corrected. In the case of significant conditions adverse to quality, it implements measures to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude repetition. The applicant stated that it accomplishes corrective actions for both safety related and nonsafety related SCs through the existing Corrective Action Program.

Confirmation Process The applicant stated that the Corrective Action Program includes the requirement that measures be taken to preclude repetition of significant conditions adverse to quality. These measures include actions to verify the effective implementation of proposed corrective actions. Corrective actions for both safety related and nonsafety related SCs are accomplished through the existing Corrective Action Program. The confirmation process is part of the Corrective Action Program. For significant conditions adverse to quality, the process includes reviews to assure that (1) proposed actions are adequate, (2) open corrective actions are tracked and reported, and (3) corrective action effectiveness is reviewed for root cause determination.

Administrative Controls The applicant accomplishes administrative control for both safety-related and nonsafety related SCs in accordance with the existing Document Control Program based on the quality assurance program description (QAPD).

3.0.4.2 Staff Evaluation

RAI 2.1-6

The NRC staff reviewed the applicant's QA controls for AMPs as described in the LRA to assure that the aging management activities are consistent with the staff's guidance described in Section A.2, "Quality Assurance for Aging Management Programs (BTP IQMB-1)," of the SRP-LR regarding quality assurance attributes of AMPs. Based on the staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in Section B.0.3 of the LRA are consistent with the staff's position regarding quality assurance for aging management. In particular, the applicant noted that its QA Program provides elements of Corrective Actions, Confirmation Process, and Administrative Controls for both safety related and nonsafety related SSCs. However, the applicant did not describe the use of the QA Program and its associated attributes in Appendix A to the LRA. Therefore, in RAI 2.1-6, the staff requested the applicant to clarify its position with regard to the quality attributes of AMPs in Appendix A to the LRA. Specifically, consistent with BTP IQMB-1, the applicant should either document a commitment to expand the scope of its program under Appendix B to 10 CFR Part 50 to include nonsafety-related SCs subject to an AMR to address the AMP quality attributes during the period of extended operation or propose an alternative means to address this issue.

The applicant responded to RAI 2.1-6 by letter dated May 7, 2004. In this response, the applicant stated that it will revise the UFSAR Supplement in Appendix A to the LRA to clarify its position on the quality attributes of AMPs. The applicant will add the following paragraph to LRA Section A.2.1, "Aging Management Programs and Activities":

> The CNP Quality Assurance Program Description implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Section A.2 of NUREG-1800, Standard Review Plan for the Review of license Renewal Applications for Nuclear Power Plants. published July 2001. The Quality Assurance Program Description includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety related and non-safety related structures, systems, and components that are within the scope of license renewal.

The staff determined that application of the QAPD to both safety related and nonsafety related SSCs within the scope of license renewal is consistent with the staff position contained in BTP IQMB-1. Therefore, on this basis, RAI 2.1-6 is resolved.

3.0.4.3 Conclusion

The staff finds that the QA attributes of the applicant's AMPs are consistent with 10 CFR 54.21(a)(3). Specifically, the applicant described the quality attributes of the programs and activities for managing the effects of aging for both safety-related and nonsafety-related SSCs within the scope of license renewal. It stated that the Quality Assurance Program under Appendix B to 10 CFR Part 50 provides corrective actions, confirmation processes, and administrative controls. Therefore, the staff concluded that the applicant adequately described the quality attributes of its AMPs.

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and RCS components and component groups associated with the following systems:

- reactor vessel and control rod drive mechanism (CRDM) pressure boundary
- reactor vessel internals
- Class 1 piping, valves, and reactor coolant pumps (RCPs)
- pressurizer
- steam generators

3.1.1 Summary of Technical Information in the Application

In Section 3.1 of the LRA, the applicant provided the AMR results for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types listed in Tables 2.3.1-1 through 2.3.1-5 of the LRA. The applicant also listed the materials, environments, aging effects requiring management (AERMs), and AMPs associated with each system.

In LRA Table 3.1.1, "Summary of Aging Management Programs for the Reactor Coolant System Evaluated in Chapter IV of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types. In Section 3.1.2.2 of the LRA, the applicant provided information concerning Table 3.1.1 components for which the GALL Report recommends further evaluation.

3.1.2 Staff Evaluation

The staff reviewed Section 3.1 of the LRA to understand the applicant's review process and to determine whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the reactor vessel, internals, RCS, pressurizer, and steam generator components that are within the scope of license renewal and subject to an AMR so 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 performed an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Section 3.1.2.1 of this SER summarizes the staff's audit findings.

The staff also audited and reviewed those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations are consistent with the acceptance criteria in Section 3.1.3.2 of the SRP-LR. Section 3.1.2.2 of this SER summarizes this aspect of the staff's audit findings.

The staff conducted a technical review of the remaining AMRs that are not consistent with the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects, and whether the aging effects listed are appropriate for the combination of materials and environments specified. Section 3.1.2.3 of this SER summarizes the staff's review findings.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provide an adequate description of the programs credited with managing or monitoring aging for the reactor vessel, internals, and RCS system components and component groups.

Table 3.1-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.1 that are addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Internals, and Reactor Coolant System Components Listed in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
RCPB (Item Number 3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.1)
Steam generator shell assembly (Item Number 3.1.1-2)	Loss of material due to pitting and crevice corrosion	Inservice Inspection; Water Chemistry	Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Steam Generator Integrity Program (B.1.31)	Consistent with GALL, which recommends further evaluation (See 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) (Item Number 3.1.1-4)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G to 10 CFR Part 50 and RG 1.99	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.3)
Reactor vessel beltline shell and welds (Item Number 3.1.1-5)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Reactor Surveillance Integrity Program (B.1.26)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.3)
Westinghouse and B&W baffle/former bolts (Item Number 3.1.1-6)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant specific	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Small-bore RCS and connected systems piping (Item Number 3.1.1-7)	Crack initiation and growth due to SCC, IGSCC, and thermal and mechanical loading	Inservice Inspection; Water Chemistry; One-Time Inspection	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Small Bore Piping Program (B.1.30)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.4)
Vessel shell (Item Number 3.1.1-10)	Crack growth due to cyclic loading	TLAA	TLAA—Under Clad Cracking	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.5)
Reactor internals (Item Number 3.1.1-11)	Changes in dimension due to void swelling	Plant specific	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Reactor Vessel Internals Cast Austenitic Stainless Steel Program (B.1.28)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.6)
PWR core support pads, instrument tubes (bottom-head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains (Item Number 3.1.1-12)	Crack initiation and growth due to SCC and/or PWSCC	Plant specific	Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Alloy 600 Aging Management Program (B.1.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Pressurizer Examinations Program (B.1.24)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.7)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
CASS RCS piping (Item Number 3.1.1-13)	Crack initiation and growth due to SCC	Plant specific	Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.7)
Pressurizer instrumentation penetrations and heater sheaths and sleeves made of nickel-alloys (Item Number 3.1.1-14)	Crack initiation and growth due to PWSCC	Inservice Inspection; Water Chemistry	Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Alloy 600 Aging Management Program (B.1.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.7)
Westinghouse and B&W baffle former bolts (Item Number 3.1.1-15)	Crack initiation and growth due to SCC and IASCC	Plant specific	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.8)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Westinghouse and B&W baffle former bolts (Item Number 3.1.1-16)	Loss of preload due to stress relaxation	Plant specific	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.9)
Steam generator feedwater impingement plate and support (Item Number 3.1.1-17)	Loss of section thickness due to erosion	Plant specific	Not applicable	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.10)
Alloy 600 steam generator tubes, repair sleeves, and plugs (Item Number 3.1.1-18)	Crack initiation and growth due to PWSCC, ODSCC, and/or IGA; 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 Integrity Program (B.1.31); Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (B.1.40.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.11)
Tube support lattice bars made of carbon steel (Item Number 3.1.1-19)	Loss of section thickness due to FAC	Plant specific	Not applicable	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.12)
Carbon steel tube support plate (Item Number 3.1.1-20)	Ligament cracking due to corrosion	Plant specific	Not applicable	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.13)
Steam generator feedwater inlet ring and supports (Item Number 3.1.1-21)	Loss of material due to FAC	(CE) Steam Generator Feedwater Ring Inspection	Not applicable	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2.14)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor vessel closure studs and stud assembly (Item Number 3.1.1-22)	Crack initiation and growth due to SCC and/or IGSCC	Reactor Head Closure Studs	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
CASS pump casing and valve body (Item Number 3.1.1-23)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
CASS piping (Item Number 3.1.1-24)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Cast Austenitic Stainless Steel Evaluation Program (B.1.7); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Pressurizer Examinations Program (B.1.24)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
BWR piping and fittings; steam generator components (Item Number 3.1.1-25)	Wall thinning due to FAC	Flow Accelerated Corrosion	Flow-Accelerated Corrosion Program (B.1.12); Chemistry Control Program (B.1.40)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
RCPB valve closure bolting, manway and holding bolting, and closure bolting in high-pressure and high-temperature systems (Item Number 3.1.1-26)	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	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Bolting and Torquing Activities Program (B.1.2); Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
CRD nozzle (Item Number 3.1.1-35)	Crack initiation and growth due to PWSCC	Ni-Alloy Nozzles and Penetrations; Water Chemistry	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Water Chemistry Control Program (B.1.40); Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program (B.1.9)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor vessel nozzles safe ends and CRD; RCS components (except CASS and bolting) (Item Number 3.1.1-36)	Crack initiation and growth due to cyclic loading, and/or SCC and PWSCC	Inservice Inspection; Water Chemistry	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Water Chemistry Control Program (B.1.40); Alloy 600 Aging Management Program (B.1.1); Pressurizer Examinations Program (B.1.24)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor vessel internals CASS components (Item Number 3.1.1-37)	Loss of fracture toughness due thermal aging, neutron irradiation embrittlement, and void swelling	Thermal Aging and Neutron Irradiation Embrittlement	Cast Austenitic Stainless Steel Evaluation Program (B.1.7)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
External surfaces of carbon steel components in RCS pressure boundary (Item Number 3.1.1-38)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Steam generator secondary manways and handholds (carbon steel) (Item Number 3.1.1-39)	Loss of material due to erosion	Inservice Inspection	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor internals, reactor vessel closure studs, and core support pads (Item Number 3.1.1-40)	Loss of material due to wear	Inservice Inspection	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14); Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Bottom-Mounted Instrumentation Thimble Tube Inspection Program (B.1.5)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Pressurizer integral support (Item Number 3.1.1-41)	Crack initiation and growth due to cyclic loading	Inservice Inspection	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Upper and lower internals assembly (Westinghouse) (Item Number 3.1.1-42)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part and/or Neutron Noise Monitoring	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor vessel internals in fuel zone region (except Westinghouse and B&W baffle former bolts) (Item Number 3.1.1-43)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	PWR Vessel Internals; Water Chemistry	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Steam generator upper and lower heads, tubesheets, and primary nozzles and safe ends (Item Number 3.1.1-44)	Crack initiation and growth due to SCC, PWSCC, and/or IASCC	Inservice Inspection; Water Chemistry	Water Chemistry Control Program (B.1.40); Alloy 600 Aging Management Program (B.1.1); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Vessel internals (except Westinghouse and B&W baffle former bolts) (Item Number 3.1.1-45)	Crack initiation and growth due to SCC and IASCC	PWR Vessel Internals; Water Chemistry	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Water Chemistry Control Program (B.1.40); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor internals (B&W screws and bolts) (Item Number 3.1.1-46)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part Monitoring	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor vessel closure studs and stud assembly (Item Number 3.1.1-47)	Loss of material due to wear	Reactor Head Closure Studs	Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)
Reactor internals (Westinghouse upper and lower internal assemblies, CE bolts and tie rods) (Item Number 3.1.1-48)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part Monitoring	Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (B.1.27); Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (B.1.14)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.1)

The staff's review of the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types followed one of several approaches. One approach, documented in Section 3.1.2.1 of this SER, involves the staff's review of the AMR results for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.1.2.2 of this SER, involves the staff's review of the AMR results for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.1.2.3 of this SER, involves the staff's review of the AMR results for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. Section 3.0.3 of this SER documents the staff's review of AMPs that are credited to manage or monitor the aging effects of the reactor vessel, internals, and RCS components and component groups.

3.1.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Not Recommended

Summary of Technical Information in the Application

In Section 3.1.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the reactor vessel, internals, RCS, pressurizer, and steam generator components:

- Reactor Vessel Integrity Program
- Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- Alloy 600 Aging Management Program
- Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program
- Bottom-Mounted Instrumentation Thimble Tube Inspection Program
- Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program
- Reactor Vessel Internals Cast Austenitic Stainless Steel Program
- Cast Austenitic Stainless Steel Evaluation Program
- Small Bore Piping Program
- Boric Acid Corrosion Prevention Program
- Bolting and Torquing Activities Program
- Pressurizer Examinations Program
- Steam Generator Integrity Program
- Flow-Accelerated Corrosion Program

Staff Evaluation

In Tables 3.1.2-1 through 3.1.2-5 of the LRA, the applicant provided a summary of AMRs for the reactor vessel, internals, RCS, pressurizer, and steam generators, and identified which AMRs it considered to be consistent with the GALL Report.

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 does not recommend further evaluation, the staff performed an audit and review to determine whether The GALL Report evaluation bounds the plant-specific components contained in these GALL Report component groups.

The applicant provided a note for each AMR line item. The notes describe the alignemnt of the information in the tables with the information in the GALL Report. The staff audited those AMRs with notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. However, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. In addition, the staff reviewed and confirmed that the identified exceptions to the GALL AMPs are acceptable. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report, and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with, the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant could not find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with, the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff also verified whether the AMR line item of the different component is applicable to the component under review. In addition, the staff reviewed and confirmed whether the identified exceptions to the GALL AMPs are acceptable. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but the applicant credited a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect in a manner consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff reviewed the information provided in the LRA and program bases documents, which are available at the applicant's engineering office. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. The following sections discuss the staff's evaluation.

3.1.2.1.1 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

To manage loss of fracture toughness resulting from thermal aging embrittlement of the cast austenitic stainless steel (CASS) pressurizer spray head, the GALL Report recommends no further evaluation if this aging effect is managed using a program consistent with GALL AMP

XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." In the LRA, the applicant described CNP AMP B.1.7, "Cast Austenitic Stainless Steel Evaluation" as consistent with GALL AMP XI.M12. However, the pressurizer spray head is not within its scope. In the LRA, the applicant proposed to use CNP AMP B.1.24, "Pressurizer Examinations," instead to manage this aging effect. Section 3.0.3.3.9 of this SER documents the staff's evaluation of this plant-specific program.

The CNP Pressurizer Examinations Program specifies one-time inspection using visual examination VT-3 to manage reduction of fracture toughness. This approach is not consistent with GALL AMP XI.M12, which provides for volumetric examination or, alternatively, a plant- or component-specific flaw tolerance evaluation to demonstrate that the thermally embrittled material has adequate toughness.

By letter dated June 30, 2004, in RAI B.1.24-2, the staff asked the applicant to justify its use of the visual examination VT-3 instead of a visual examination VT-1 for the one-time inspection of the spray head and its associated components in either Unit 1 or Unit 2. Additionally, the staff asked the applicant to provide information regarding acceptance criteria, the evaluation methodology for the disposition of indications, and the need for successive examinations for the one-time inspection of the spray head, spray head locking bar, and coupling. The staff considers that it is adequate to perform a one-time VT-3 visual examination of spray head components in one unit. Section 3.0.3.3.9 of this SER provides the complete staff evaluation of the response to RAI B.1.24-2.

The staff finds that based on the Pressurizer Examinations Program, the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.2 Core Exit Thermocouple Nozzle Assembly

During the audit and review, the staff noted that the GALL Report does not list the core exit thermocouple nozzle assembly, including holddown nut, compression collar, and lockwasher. By letter dated April 23, 2004, the applicant provided the following explanation for their inclusion:

> The thermocouple nozzle assembly pressure-retaining items include the head port adapter (pressure housing), holddown nut, compression collar, Grafoil® seals, seal carrier assembly, and lockwasher. The head port adapter, holddown nut, and compression collar are fabricated from stainless steel and are subject to aging management review. The short-lived Grafoil seals, seal carrier assembly, and lockwasher are replaced each refueling outage and are not subject to an AMR.
>
> The AMR determined that the compression collar and holddown nut are part of the bolted connection used to connect the head port adapter to the core exit thermocouple column, which is part of the reactor vessel internals. The stainless steel holddown nut and compression collar are exposed to an external-ambient environment in which there are no aging effects that require management.

The stainless steel thermocouple nozzle assembly head port adapter is exposed to an internal environment of borated water and an external-ambient environment. The applicable aging effects include cracking and loss of material, which will be managed by the inservice inspection program and water chemistry control program throughout the period of extended operation. The thermocouple nozzle assembly head port adapter is attached to a CRDM head nozzle adapter by means of a threaded connection and a canopy seal weld. The canopy seal weld is exposed to an external-ambient environment. The applicable aging effect of the canopy seal weld is cracking, which is managed by the boric acid corrosion prevention program.

Section 3.0.3.2.1 of this SER documents the staff's evaluation of CNP AMP B.1.4, "Boric Acid Corrosion Prevention." The staff evaluated CNP AMP B.1.40.1, "Water Chemistry Control—Primary and Secondary Water Chemistry Control Program," and CNP AMP B.1.14, "Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD," as documented in Sections 3.0.3.2.15 and 3.0.3.1 of this SER, respectively.

With respect to the Water Chemistry Control and Inservice Inspection Programs, the applicant manages aging of this component type in a manner consistent with the recommendations of the GALL Report. The staff reviewed the Boric Acid Corrosion Prevention Program; Section 3.0.3.2.1 of this SER discusses the results of that review.

The staff finds that for the Water Chemistry Control and Inservice Inspection Programs, the applicant has demonstrated that, given an acceptable Boric Acid Corrosion Prevention Program, it will adequately manage he effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.3 Loss of Mechanical Closure Integrity

The GALL Report recommends the management of the loss of mechanical closure integrity of stainless steel and nickel-based alloy bolted fasteners by stress relaxation in borated water using GALL AMP XI.M14, "Loose Part Monitoring," or GALL AMP XI.M15, "Neutron Noise Monitoring," in addition to ISI.

In the LRA, the applicant proposed to manage this aging effect using the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (CNP AMP B.1.27) and the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Section 3.0.3.1 of this SER documents the staff's evaluation of these programs.

In the LRA, the applicant stated that the proposed new Reactor Vessel Internals Program is intended as an alternative to the Loose Part Monitoring Program. The applicant's program includes managing the aging effects of loss of preload and loss of mechanical closure integrity and will be implemented before the period of extended operation. The staff finds that this would provide adequate management of the aging mechanism. However, the AMR for the core support holddown spring does not identify the Inservice Inspection Program as applicable to this aging effect. During the audit, the staff requested that the applicant address this issue. By letter dated April 23, 2004, in response to this request, the applicant provided additional clarification. In its response, the applicant stated that the Inservice Inspection Program includes the holddown spring (already documented in the LRA for the aging effect of cracking), and that the Reactor Vessel Internals Program will augment the ISI to include acceptable inspection methods for bolted joints, including those necessary to demonstrate that loss of closure integrity from stress relaxation (i.e., loss of preload) will be managed.

The staff finds that based on the Reactor Vessel Internals Program, the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.4 Flow-Accelerated Corrosion

In the LRA, this component grouping includes the main steam nozzles and the Unit 2 feedwater elbow thermal liners. The GALL Report recommends management of loss of material from the feedwater nozzles as a result of FAC, but the applicant does not manage FAC for these components, which are protected from FAC by nickel-based alloy thermal sleeves (Unit 1) and carbon steel thermal liners (Unit 2). The sleeves are not subject to FAC; therefore, no program is required for management of this aging effect. The applicant uses CNP AMP B.1.12, "Flow-Accelerated Corrosion," supplemented by the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) to manage this effect. This is consistent with the GALL Report and therefore acceptable to the staff. Sections 3.0.3.1 and 3.0.3.2.15 of this SER, respectively, document the staff's evaluation of these programs.

The staff finds that based on the programs identified above, the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

On the basis of its audit and review, the staff determined that for all other AMRs not requiring further evaluation, as identified in LRA Table 3.1.1 (Table 1), the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion

The staff has verified the applicant's claim of consistency with the GALL Report. The staff has also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for these components so that their intended functions 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 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application

In Section 3.1.2.2 of the LRA, the applicant provided further evaluation of aging management, as recommended by the GALL Report for the reactor vessel, internals, and RCS. The applicant provided information concerning its management of the following aging effects:

- cumulative fatigue damage (PWR/BWR)
- loss of material due to pitting and crevice corrosion (PWR/BWR)
- loss of fracture toughness due to neutron irradiation embrittlement (PWR/BWR)
- crack initiation and growth due to thermal and mechanical loading or stress cracking (PWR/BWR)
- crack growth due to cyclic loading (PWR)
- changes in dimension due to void swelling (PWR)
- crack initiation and growth due to SCC or PWSCC (PWR)
- crack initiation and growth due to SCC or IASCC (PWR)
- loss of preload due to stress relaxation (PWR)
- loss of section thickness due to erosion (PWR)
- crack initiation and growth due to PWSCC, outer diameter stress corrosion cracking (ODSCC), or IGA; or loss of material due to wastage and pitting corrosion; or loss of section thickness due to fretting and wear; or denting due to corrosion of carbon steel tube support plate (PWR)
- loss of section thickness due to FAC
- ligament cracking due to corrosion (PWR)
- loss of material due to FAC (PWR)

Staff 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 addresses the issues that require further evaluation. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.1.2.2 of the SRP-LR. The staff's audit and review report provides details of this effort.

The GALL Report indicates that further evaluation should be performed for the aging effects described in the following sections.

3.1.2.2.1 Cumulative Fatigue Damage

Fatigue is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. Section 4.3 of this SER provides the staff's evaluation of this TLAA.

3.1.2.2.2 Loss of Material due to Pitting and Crevice Corrosion

In LRA Section 3.1.2.2.2, the applicant addressed the loss of material of steam generator assemblies due to pitting and crevice corrosion.

Section 3.1.2.2.2 of the SRP-LR states that the loss of material due to pitting and crevice corrosion could occur in the steam generator shell assembly. The existing program relies on control of water chemistry to mitigate corrosion and ISI to detect loss of material. NRC IN 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," states that if general corrosion pitting of the shell exists, the current program may not be sufficient. In that case, the GALL Report recommends augmented inspections to manage the aging effect.

The GALL Report recommends the following two programs to manage the aging of steam generator assemblies due to pitting and crevice corrosion:

(1) GALL AMP XI.M1 to detect loss of material

(2) GALL AMP XI.M2 to mitigate corrosion

The GALL Report recommends a plant-specific program to conduct augmented inspections.

In the LRA, the applicant credited the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) to manage the loss of material due to pitting and crevice corrosion. Section 3.0.3.2.15 of this SER documents the staff's evaluation of CNP AMP B.1.40.1. The Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14) supplements this program for secondary-side external components of the steam generator within the scope of that program. Section 3.0.3.1 of this SER documents the staff's evaluation of the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program.

In LRA Section 3.1.2.2.2, the applicant did not discuss secondary-side internal components of the steam generator that are outside the scope of the Inservice Inspection Program. In Table 3.1.2-1, the applicant stated that it supplements management of general, pitting, and crevice corrosion for the steam generator shell assembly and attached components, as well as components of the secondary-side internals, using CNP AMP B.1.31, "Steam Generator Integrity Program." Section 3.0.3.1 of this SER documents the staff's evaluation of the Steam Generator Integrity Program.

The applicant credited the Inservice Inspection Program, which is evaluated in Section 3.0.3.1 of this SER, and the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program," which is evaluated in Section 3.0.3.2.15 of this SER, for managing the loss of material due to pitting and crevice corrosion on the internal surfaces of the steam generator shell.

The staff reviewed NRC IN 90-04, which identifies the need to augment inspections beyond the requirements of ASME Code Section XI if general corrosion pitting of the steam generator shell is known to exist, to differentiate isolated cracks from inherent geometric conditions. The applicant maintained that these concerns are not applicable to CNP because it has not experienced significant pitting corrosion of the steam generator shell. The applicant replaced the Unit 1 steam generators in 2000 and the Unit 2 steam generators in 1988.

The staff reviewed operating experience, which indicates that no pitting corrosion of the steam generator shell has been detected to date, and that water chemistry have been maintained for these new steam generators in accordance with EPRI guidelines. The staff finds that the augmented inspections recommended by NRC IN 90-04, as referenced in the SRP-LR, do not currently apply to the CNP steam generators.

In the LRA, the applicant stated that the steam generator tubesheet is made of LAS, clad on the primary side with nickel-based alloy. Using only the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program to manage the loss of material from the primary side (in treated, borated water) is consistent with the GALL Report and acceptable to the staff. However, the staff does not consider this program to be sufficient for managing this loss of material from the secondary side of the tubesheet. During the audit, the applicant was asked to justify this position. By letter dated April 23, 2004, the applicant responded by stating that the Steam Generator Integrity Program and Water Chemistry Control Program will manage loss of material from the secondary side of the tubesheet. This is consistent with the GALL Report and therefore acceptable to the staff.

In addition, because the applicant had not detected pitting corrosion on the steam generator shell since installation, the staff finds that augmented inspections are not required and that the current Water Chemistry Control and Inservice Inspection Programs, supplemented by the Steam Generator Integrity Program, are consistent with the recommendations of the GALL Report and therefore adequate for managing this aging effect.

The staff finds that, based on the programs identified above, the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.3 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

Neutron irradiation embrittlement is a TLAA, as defined in 10 CFR 54.3. Section 4.2 of this SER provides the staff's evaluation of the TLAA on neutron irradiation embrittlement.

3.1.2.2.4 Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress-Corrosion Cracking

In LRA Section 3.1.2.2.4, the applicant addressed the potential crack initiation and growth that could be caused by thermal and mechanical loading or SCC (including IGSCC), and that could occur in small-bore RCS and connected system piping less than 4 inches nominal pipe size (NPS 4").

Section 3.1.2.2.4 of the SRP-LR states that the GALL Report recommends that a plant-specific destructive examination or a 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 period of extended operation. The applicant should verify that service-induced weld cracking is not occurring in small-bore piping less than NPS 4". A one-time inspection of a sample of locations is an acceptable method to ensure that the aging effect is not occurring and that the component's intended function will be maintained during the period of extended operation. As indicated in ASME Code Section XI, 1995 Edition, Examination Category B-J or B-F, small-bore piping, defined as piping less than NPS 4", does not receive volumetric inspection.

The GALL Report recommends GALL AMP XI.M1 to detect loss of material and GALL AMP XI.M2 to mitigate SCC.

The staff reviewed LRA Section 3.1.2.2.4. The applicant uses the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14) the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) to manage cracking from SCC. Sections 3.0.3.1 and 3.0.3.2.15 of this SER, respectively, document the staff's evaluation of these programs. In addition, the applicant uses CNP AMP B.1.30, "Small Bore Piping," which includes a one-time inspection to confirm that significant cracking is not occurring. Section 3.0.3.1 of this SER documents the staff's evaluation of this program. The staff finds this approach to be consistent with the recommendations of the GALL Report and therefore acceptable. The implementation of the Small Bore Piping Program is Commitment #22 of Appendix A in this SER.

The staff finds that the applicant's AMR results are consistent with the GALL Report, and that the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.5 Crack Growth due to Cyclic Loading

As stated in the SRP-LR, fatigue is a TLAA as defined in 10 CFR 54.3. Evaluation of TLAAs is required in accordance with 10 CFR 54.21(c)(1). Section 4.3 of this SER provides the staff's evaluation of the crack growth due to cyclic loading at CNP. In performing this review, the staff followed the guidance in Section 4.3 of the SRP-LR.

3.1.2.2.6 Changes in Dimension due to Void Swelling

In LRA Section 3.1.2.2.6, the applicant addressed changes in dimension resulting from void swelling that could occur in reactor internals components.

Section 3.1.2.2.6 of the SRP-LR states that the GALL Report recommends that changes in dimension due to void swelling in reactor internals components be evaluated to ensure the adequate management of this aging effect. The GALL Report recommends the evaluation of a plant-specific AMP to manage the effects of changes in dimension due to void swelling and the loss of fracture toughness associated with such swelling.

In LRA Section 3.1.2.2.6 and Table 3.1.1, the applicant credited the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (CNP AMP B.1.27) to manage changes in dimension caused by void swelling of RVI.

In LRA Table 3.1.2-2, page 3.1-51, the applicant credited the Reactor Vessel Internals Cast Austenitic Stainless Steel Program to manage distortion of the lower support plate and lower core plate support column cap in a treated water environment. Additionally, in Sections B.1.27 and B.1.28, "Reactor Vessel Internals Cast Austenitic Stainless Steel," of Appendix B to the

LRA, the applicant described each program as managing the aging effect of distortion due to void swelling. The implementation of the Reactor Vessel Internals Cast Austenitic Stainless Steel Program is Commitment #20 in Appendix A of this SER.

RAI 3.1.2-4

In RAI 3.1.2-4, the staff requested that the applicant update LRA Section 3.1.2.2.6 and Table 3.1.1, Item 3.1.1-11, to credit the Reactor Vessel Internals Cast Austenitic Stainless Steel Program with managing this aging effect or to justify why it should not be credited with managing this aging effect.

In its response dated September 21, 2004, the applicant agreed with the staff that, as described in LRA Section B.1.28, the Reactor Vessel Internals Cast Austenitic Stainless Steel Program will manage change in dimension by void swelling of RVI CASS components. The applicant stated that LRA Section 3.1.2.2.6 and LRA Table 3.1.1, Item 3.1.1-11, should have included this program. Table 3.1.2-2 of the LRA correctly identifies the CASS components that are susceptible to change in dimension by void swelling (distortion) and credits the Reactor Vessel Internals Cast Austenitic Stainless Steel Program with managing this aging effect. Table 3.1.1, Item 3.1.1-37, of the LRA also credits this program for the management of void swelling.

On the basis of its review of the applicant's response to RAI 3.1.2-4 and the programs it credited to manage changes in dimension due to void swelling, the staff finds that the applicant's AMR results are consistent with the GALL Report, and that the applicant has demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, the concern described in RAI 3.1.2-4 is resolved.

3.1.2.2.7 Crack Initiation and Growth due to Stress-Corrosion Cracking or Primary Water Stress-Corrosion Cracking

In LRA Section 3.1.2.2.7, the applicant proposed to manage cracking of nickel-based alloy components due to PWSCC using the plant-specific CNP AMP B.1.1, "Alloy 600 Aging Management." Section 3.0.3.3.1 of this SER documents the staff's evaluation of this program.

The applicant also stated, in the LRA, that the Alloy 600 Aging Management Program is supplemented by the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) and the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Sections 3.0.3.2.15 and 3.0.3.1 of this SER, respectively, document the staff's evaluations of these AMPs.

In the LRA, the applicant further stated that it will manage cracking of the pressurizer spray head assembly using CNP AMP B.1.24, "Pressurizer Examinations." Section 3.0.3.3.9 of this SER documents the staff's evaluation of this program. The applicant will manage crack initiation and growth resulting from SCC in reactor coolant piping and fittings using the Water Chemistry Control and the Inservice Inspection Programs.

In addition to the plant-specific AMP recommended by the GALL Report, the applicant agreed to augment ISI when industry programs identify specific locations or appropriate inspections for the management of this aging effect.

The staff finds the applicant's approach for managing crack initiation and growth due to SCC and PWSCC to be consistent with the GALL Report and therefore acceptable. The applicant agreed to submit the program for review by the staff prior to the period of extended operation. The staff finds that the applicant appropriately evaluated AMR results that address these aging mechanisms, 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

In LRA Section 3.1.2.2.8, the applicant addressed crack initiation and growth resulting from SCC or IASCC that could occur in baffle/former bolts in the reactor.

Section 3.1.2.2.8 of the SRP-LR states that crack initiation and growth due to SCC or IASCC could occur in baffle/former bolts in the reactors. The GALL Report recommends further evaluation to ensure the adequate management of these aging effects.

The applicant proposed to use the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (CNP AMP B.1.27), in conjunction with the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Section 3.0.3.1 of this SER documents the staff's evaluation of these two programs. The applicant also credited the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) for mitigating damage caused by SCC. Section 3.0.3.2.15 of this SER documents the staff's evaluation of CNP AMP B.1.40.1.

In the LRA, the applicant stated that it will use volumetric inspections of baffle/former bolt critical locations to assess cracking. No detectable crack will be considered acceptable for a baffle bolt, and the critical number (and location) of baffle bolts that must remain intact will be determined by analysis as part of this program. The industry is addressing the issue of baffle bolt cracking through the activities of the PWR MRP ITG. Those activities will determine, develop, and implement the necessary steps and plans to manage the applicable aging effects on a plant-specific basis. In the LRA, the applicant stated it will follow these efforts and will apply further understanding of these aging effects as an additional bases for the inspections under this program. The staff finds this action to be acceptable.

3.1.2.2.9 Loss of Preload due to Stress Relaxation

In LRA Section 3.1.2.2.9, the applicant addressed the loss of preload due to stress relaxation that could occur in baffle/former bolts in the reactor.

Section 3.1.2.2.9 of the SRP-LR states that the loss of preload as a result of stress relaxation could occur in baffle/former bolts in the reactor. The GALL Report recommends further evaluation to ensure the adequate management of this aging effect.

In the LRA, the applicant proposed to use the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program (CNP AMP B.1.27), in conjunction with the Inservice

Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Section 3.0.3.1 of this SER documents the staff's evaluation of the plant-specific CNP AMP B.1.27 and CNP AMP B.1.14. As recommended by the GALL Report, the applicant augments the ISIs by volumetric examination to detect and manage this aging effect.

On the basis that the applicant's Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program will be consistent with GALL AMP XI.M16, the staff finds the applicant's approach for managing the loss of preload due to stress relaxation to be consistent with the GALL Report and therefore acceptable.

3.1.2.2.10 Loss of Section Thickness due to Erosion

In LRA Section 3.1.2.2.10, the applicant addressed the loss of section thickness due to erosion that could occur in steam generator feedwater impingement plates and supports.

Section 3.1.2.2.10 of the SRP-LR states that the loss of section thickness from erosion could occur in steam generator feedwater impingement plates and supports. The GALL Report recommends further evaluation of a plant-specific AMP to ensure the adequate management of this aging effect.

The applicant stated, in the LRA, that its steam generator design does not include impingement plates. Because impingement plates are not part of the CNP steam generator design, the staff finds that this aging effect does not require management at CNP.

3.1.2.2.11 Crack Initiation and Growth due to Primary Water Stress-Corrosion Cracking, Outside Diameter Stress-Corrosion Cracking, or Intergranular Attack; or Loss of Material due to Wastage and Pitting Corrosion; or Loss of Section Thickness due to Fretting and Wear; or Denting due to Corrosion of Carbon Steel Tube Support Plate

In CNP LRA Section 3.1.2.2.11, the applicant addresses crack initiation and growth due to PWSCC, ODSCC, or IGA or loss of material due to wastage and pitting corrosion or deformation due to corrosion that could occur in nickel-based alloy components of the steam generator tubes and plugs.

SPR-LR Section 3.1.2.2.11 states that crack initiation and growth due to PWSCC, ODSCC, or IGA or loss of material due to wastage and pitting corrosion or deformation due to corrosion could occur in Alloy 600 components of the steam generator tubes, repair sleeves and plugs. The applicant agreed to conform to the steam generator degradation management program described in NEI 97-06. The GALL Report recommends the development of an AMP based on the recommendations of staff-approved NEI 97-06 guidelines, or another alternate regulatory basis for steam generator degradation management, to ensure the adequate management of this aging effect.

To manage several of the effects of aging, the applicant credits the Steam Generator Integrity Program (CNP AMP B.1.31) in the LRA. Aging effects managed by the Steam Generator Integrity Program include crack initiation and growth resulting from the PWSCC, SCC, or IGA or loss of material caused by wastage and pitting corrosion or deformation due to corrosion which could occur in nickel-based alloy components of the steam generator tubes and plugs. Section 3.0.3.1 of this SER documents the staff's evaluation of the Steam Generator Integrity Program.

In addition, the applicant stated that it will supplement this program with the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) and the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Sections 3.0.3.2.15 and 3.0.3.1 of this SER, respectively, discuss the staff's evaluations of these programs. For general and pitting corrosion, as well as for the assessment of tube integrity and plugging or repair criteria of flawed tubes, the Steam Generator Integrity Program acceptance criteria conform to NEI 97-06 guidelines.

On the basis of its review of the Water Chemistry Control and Inservice Inspection Programs, the staff finds that the applicant appropriately evaluated the AMR results involving plant-specific programs to address these aging mechanisms, as recommended in the GALL Report.

3.1.2.2.12 Loss of Section Thickness due to Flow-Accelerated Corrosion

In LRA Section 3.1.2.2.12, the applicant addressed the loss of section thickness due to FAC that could occur in tube support lattice bars made of carbon steel.

Section 3.1.2.2.12 of the SRP-LR states that the loss of section thickness due to FAC could occur in tube support lattice bars made of carbon steel. The GALL Report recommends the evaluation of a plant-specific AMP and, on the basis of the guidelines of NRC GL 97-06, development of an inspection program for steam generator internals to ensure the adequate management of this aging effect.

In the LRA, the applicant stated that its steam generator design does not include carbon steel tube support lattice bars.

On the basis that carbon steel tube support lattice bars are not part of the CNP steam generator design, the staff finds that this aging effect does not require management at CNP.

3.1.2.2.13 Ligament Cracking due to Corrosion

In LRA Section 3.1.2.2.13, the applicant addressed ligament cracking resulting from corrosion that could occur in carbon steel components in the steam generator tube support plate.

Section 3.1.2.2.13 of the SRP-LR states that ligament cracking due to corrosion could occur in carbon steel components in the steam generator tube support plate. All PWR licensees have voluntarily agreed to conform to a steam generator degradation management program described in NEI 97-06. The GALL Report recommends the development of an AMP based on the recommendations of staff-approved NEI 97-06 guidelines, or another alternate regulatory basis for steam generator degradation management, to ensure the adequate management of this aging effect.

The applicant stated that the CNP Unit 1 steam generators do not have support plates; the steam generators in Unit 2 have tube support plates made of stainless steel, not carbon steel.

On the basis that CNP Unit 1 has no tube support plate and that the CNP Unit 2 steam generator tube support plate design does not include carbon steel components, the staff finds that this aging effect does not require management at CNP.

3.1.2.2.14 Loss of Material due to Flow-Accelerated Corrosion

In LRA Section 3.1.2.2.14, the applicant addressed the loss of material due to FAC that could occur in the feedwater inlet ring and supports.

Section 3.1.2.2.14 of the SRP-LR states that loss of material due to FAC could occur in the feedwater inlet ring and supports. As noted in NRC IN 90-04, NRC IN 91-19, and LER 50-362/90-05-01, this form of degradation has been detected only in certain Combustion Engineering (CE) System 80 steam generators. The GALL Report recommends further evaluation to ensure the adequate management of this aging effect. The GALL Report also recommends the evaluation of a plant-specific AMP because existing programs may not be capable of mitigating or detecting the loss of material caused by FAC.

In the LRA, the applicant stated that this subsection of the SRP-LR applies only to CE System 80 steam generators and notes that CNP has B&W Type 51R and Westinghouse Model 51 steam generators for which this form of degradation has not been detected.

On the basis that B&W Type 51R and Westinghouse Model 51 steam generators are not subject to FAC in the feedwater inlet ring supports, the staff finds that this component requires no AMP at CNP.

3.1.2.2.15 Quality Assurance for Aging Management of Nonsafety related Components

Section 3.0.4 of this SER provides the staff's evaluation of the applicant's Quality Assurance Program.

Conclusion

On the basis of its review, 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 determined that the applicant has adequately addressed the issues that required further evaluation. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in the SRP-LR. Because the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so 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).

3.1.2.3 AMR Results That Are Not Consistent With or Not Addressed in the GALL Report

Summary of Technical Information in the Application

In Tables 3.1.2-1 through 3.1.2-5 of the LRA, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations that are not consistent with the GALL Report.

In Tables 3.1.2-1 through 3.1.2-5, the applicant indicated, using notes F through J, that the GALL Report evaluates neither the identified component nor the material and environment combination, and provided information concerning the means for managing the aging effect.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for the component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that the GALL Report does not evaluate either the identified component or the material and environment combination.

Staff Evaluation

For component type, material, and environment combinations that the GALL Report does not evaluate, the staff reviewed the applicant's evaluation to determine whether the applicant demonstrated that it will adequately manage the effects of aging so that the component intended functions will be maintained consistent with the CLB during the period of extended operation. The following sections discuss the staff's evaluation.

3.1.2.3.1 Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

Summary of Technical Information in the Application

In Section 3.1.2.1.1 of the LRA, the applicant identified the materials, environments, and AERMs for the reactor vessel and control rod drive mechanism (CRDM) pressure boundary. The applicant identified the following programs that manage the AERMs for the reactor vessel and CRDM pressure boundary and associated pressure boundary components:

- Reactor Vessel Integrity Program
- Inservice Inspection - ASME Section XI, Subsection IWB, IWC, and IWD Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- Alloy 600 Aging Management Program
- Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program
- Bottom-Mounted Instrumentation Thimble Tube Inspection Program

The applicant identified the following aging effects associated with the reactor vessel and CRDM pressure boundary components that require management:

- cracking
- loss of material
- reduction in fracture toughness (reactor vessel beltline materials only)
- loss of mechanical closure integrity

In Table 3.1.2-1 of the LRA, the applicant provided a summary of AMRs for the Reactor Vessel and CRDM Pressure Boundary and associated pressure boundary components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited for managing them for the reactor vessel and CRDM pressure boundary components of the RCS. The staff also reviewed the applicable UFSAR Supplements to ensure that they adequately describe the AMPs.

Loss of Material in Carbon Steel, Low Alloy Steel, and Low Alloy Steel Internally Clad with Stainless Steel or Nickel-Based Alloy Exposed Externally to Potentially Leaking Borated Water

Summary of Technical Information in the Application

The applicant identified in LRA Table 3.1.2-1 that loss of material is an AERM for the following RPV components which are made of carbon steel, LAS, and LAS internally clad with stainless steel or nickel-based alloy, which may be potentially exposed externally to leaking borated water:

- bottom head, shell-nozzle course, upper head, and inlet and outlet nozzles (LAS clad with stainless steel)
- shell rings (LAS clad with stainless steel and nickel-based alloy)
- weld buildup support pads (LAS)
- vessel flange and closure head flange (LAS clad with stainless steel)
- closure studs, nuts, and washers (LAS)
- lifting lugs (LAS)
- ventilation shroud support ring (carbon steel)

The applicant credited the Boric Acid Corrosion Prevention Program (SER Section 3.0.3.2.1) with the management of the loss of material in these components.

Staff Evaluation

The applicant identified that loss of material is an applicable aging effect for carbon steel, LAS, and LAS internally clad with stainless steel or nickel-based alloy RPV components that may be potentially exposed to leaking borated water. It characterized the AMR for managing these components as either consistent with the GALL Report line item or consistent with the the GALL Report line item except for the component itself.

The Boric Acid Corrosion Prevention Program is used to manage the aging of carbon steel SCs, LAS SCs, and electrical components onto which borated water may leak. The staff evaluation and acceptance of this program can be found in Section 3.0.3.2.1. Using provisions in the Boric Acid Corrosion Prevention Program for inspecting, detecting, or monitoring the degradation of SCs that may be potentially exposed to borated water to manage the loss of material in SCs is consistent with the GALL Report line items for these listed components and, therefore, is acceptable to the staff. Hence, the staff finds that the applicant's AMR evaluation is consistent with the GALL Report, and the applicant has demonstrated 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).

Cracking in Nickel-Based Alloy and Low Alloy Steel Clad with Stainless Steel or Nickel Based Alloy Under Borated Water Environment

Summary of Technical Information in the Application

The applicant identified that cracking is an AERM for the following groups of nickel-based alloy and LAS clad with stainless steel or nickel-based alloy RPV components which are exposed to the borated water environment, as indicated in LRA Table 3.1.2-1:

- bottom head, shell-nozzle course, upper head, and inlet and outlet nozzles (LAS clad with stainless steel)
- flange and closure head flange (LAS clad with stainless steel)
- shell rings (LAS clad with stainless steel and nickel-based alloy)
- in-core instrumentation nozzles (nickel-based alloy)
- core support lugs (nickel-based alloy)

The applicant credited the Water Chemistry Control Program (SER Section 3.0.3.2.15), Inservice Inspection Program—ASME Section XI, Subsections IWB, IWC, and IWD (SER Section 3.0.3.1), and the TLAA regarding underclad cracking (SER Section 4.7.4) with the management of cracking in the first two groups of RPV components listed above. For easy referencing, this SER refers the second AMP hereafter as the Inservice Inspection Program. For the remaining three groups of RPV components, the applicant credited three AMPs with the management of cracking—the Water Chemistry Control Program, the Alloy 600 Aging Management Program (SER Section 3.0.3.3.1), and the Inservice Inspection Program.

Staff Evaluation

The applicant identified cracking as an applicable aging effect for nickel-based alloy and LAS clad with stainless steel or nickel-based alloy RPV components which are exposed to a borated water environment. The applicant characterized the AMRs for managing these components as not consistent with the GALL Report line item or not consistent with the GALL Report line item except for the component itself.

In addition to the Water Chemistry Control and the Inservice Inspection Programs, the applicant credited the TLAA regarding RPV underclad cracking, which is discussed in Section 4.7.4 of this SER, with the management of cracking in inlet and outlet nozzles and vessel flange and closure head flange. Underclad cracking is caused by reheat cracking, the use of high-heat-input welding processes on SA-508, Class 2 forgings. This TLAA has identified fatigue crack growth to be the dominant degradation mechanism for cracks in this material and has provided justification, as discussed in Section 4.7.4.2 of this SER, for managing the fatigue crack growth for 60 years for this special class of cracks in RPV LAS base metal immediately beneath the clad.

The GALL Report line item IV.A2.4-b for inlet and outlet nozzles does not call for the underclad cracking TLAA to manage cracking under a borated water environment. The GALL Report line items IV.A2.5-d, IV.A2.5-e, and IV.A2.5-f for vessel flanges do not even list cracking as an aging effect under a borated water environment. Technically, underclad cracking has less effect on RPV inlet and outlet nozzles and vessel flange and closure head flange than on RPV shell rings because the stresses associated with the former are lower. Therefore, the applicant's practice of applying the underclad cracking TLAA, which relates to RPV shell rings, to CNP RPV inlet and outlet nozzles (part of Group 1 components) and vessel flange and closure head flange (Group 2 components) exceeds GALL requirements and is acceptable.

RAI 3.1-8

As mentioned above, the applicant also credited the Water Chemistry Control and Inservice Inspection Programs for managing cracking in the first two groups of RPV components. Industry has used the Water Chemistry Control and Inservice Inspection Programs for years in operating plants to detect, size, and evaluate cracking, including underclad cracking and general SCC in these RPV components. Using the Water Chemistry Control and Inservice Inspection Programs to manage cracking in RPV inlet and outlet nozzles is consistent with the GALL Report line item IV.A2.4-b and is appropriate. Using the Water Chemistry Control and Inservice Inspection Programs to manage cracking in RPV vessel flange and closure head flange is also appropriate because the applicant exceeded the GALL Report requirements by considering cracking as an aging effect for RPV flanges. However, in RAI 3.1-8, for flaws which were detected and evaluated to date in accordance with ASME Code requirements, the staff requested that the applicant propose a plan to monitor and evaluate these flaws appropriately during the period of extended operation because disposition of these detected flaws to date was based on a period of 40 years of operation.

In the letter dated October 18, 2004, the applicant responded by stating that "[a] review of inservice inspection records determined that CNP has no rejected flaws that were accepted by analytical evaluation to the end of the service lifetime of the component." Since the applicant did not perform any flaw evaluation which would require reexamination at the end of current license, the staff considers RAI 3.1-8 closed. Hence, the staff concludes that the proposed management of cracking under a borated water environment for the Group 1 and 2 RPV components is acceptable.

RAI 3.1-9

For Group 3 components (shell ring), footnotes 1 and 8 to LRA Table 3.1.2-1 indicate that certain shell ring cladding is fabricated of nickel-based weld material (Alloy 82/182, 52/152), and PWSCC is a concern for these welds. The GALL Report line items IV.A2.5-a, IV.A2.5-b, IV.A2.5-c, and IV.A2.5-d do not list PWSCC as an aging effect for shell rings under a borated water environment. Therefore, to assess the AMR review of shell rings, the staff requested the applicant to identify all locations under "shell rings" in Table 3.1.2-1 that have nickel-based weld material exposed to a borated water environment. The staff issued this request as RAI 3.1-9.

The applicant responded in the letter dated August 11, 2004, that the only places where shell rings have a nickel-based weld material is the nickel-based weld cladding under six core support lugs around the lower shell ring. Since the applicant has provided information needed for assessing the applicability of the proposed AMPs discussed below to these specific locations in shell rings, the staff considers RAI 3.1-9 to be answered satisfactorily and the issue resolved.

The applicant credited the Water Chemistry Control, Alloy 600 Aging Management, and Inservice Inspection Programs for the management of cracking in shell rings (Group 3 components). As discussed above, the applicant's response to RAI 3.1-9 indicates that the weld cladding under six core support lugs around the lower shell ring shell rings contains Alloy 82/182 material. The applicant could not find an appropriate GALL Report line item for RPV shell rings with Alloy 82/182 material; consequently, the applicant has referenced GALL Report line item IV.C2.5-c for pressurizer shell with Alloy 82/182 cladding and adopted the Inservice Inspection and Water Chemistry Control Programs, which are recommended by the GALL Report for pressurizer shells, to manage cracking in RPV shell rings. Further, although GALL line item IV.C2.5-c does not mention the use of the Alloy 600 Aging Management Program for managing cracking in RPV shell rings, the applicant proposed, in accordance with the current industry practice on PWSCC, to include the Alloy 600 Aging Management Program to manage cracking in these components during the extended period of operation. This SER discusses PWSCC and the Alloy 600 Aging Management Program below with regard to Group 4 and 5 components for which the GALL Report has identified PWSCC as an aging mechanism. Using the Alloy 600 Aging Management, Water Chemistry Control, and Inservice Inspection Programs for the management of cracking in shell rings under a borated water environment is consistent with the GALL Report.

For Group 4 and 5 components (in-core instrumentation (ICI) nozzles and core support lugs), the GALL Report line item IV.A2.7-a for bottom head instrument tubes and line item IV.A2.6-a for core support pads/core guide lugs confirm that the primary cracking mechanism for these two groups of components is PWSCC, and the GALL Report recommends that the applicant provide a plant-specific AMP or participate in industry programs to determine an appropriate AMP for managing PWSCC. The staff's review of the Alloy 600 Aging Management Program as evaluated in Section 3.0.3.3.1of this SER concludes that the applicant's Alloy 600 Aging Management Program, which incorporates the industry effort in managing PWSCC generically, is the plant-specific AMP recommended by the GALL Report for Group 4 and 5 components. In addition, although GALL Report line items IV.A2.6-a and IV.A2.7-a does not list the Water Chemistry Control and Inservice Inspection Programs for the management of cracking in Group 4 and 5 components under a borated water environment, adding them as supplemental AMPs is prudent because improvements in water chemistry are effective in mitigating general corrosion and SCC. In addition, the Inservice Inspection Program will supplement the inspection requirements in the Alloy 600 Aging Management Program specifically designed for managing PWSCC. The staff concludes that using the Water Chemistry Control, the Alloy 600 Aging Management, and the Inservice Inspection Programs to manage cracking in ICI nozzles and core support lugs exceeds the GALL Report recommendations for these components and, therefore, is acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cracking in RPV nickel-based alloy and LAS clad with stainless steel or nickel based alloy under borated water environment, as recommended in the GALL Report. Since the applicant's AMR results are either consistent with or exceed the GALL Report requirements, the staff finds that the applicant has demonstrated that it will adequately mange the effects of aging 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).

Cracking in Stainless Steel Bottom-Mounted Instrumentation Thimble Tubes Under Borated Water Environment

Summary of Technical Information in the Application

The applicant identified in LRA Table 3.1.2-1 that cracking is an AERM for the BMI thimble tubes and bullet plugs which are made of stainless steel and are exposed to a borated water environment. The applicant credited the Water Chemistry Control and Inservice Inspection Programs with the management of cracking in the BMI thimble tubes and bullet plugs.

Staff Evaluation

RAI B.1.5-1

LRA Table 3.1.2-1 lists cracking as an AERM for bottom-mounted instrumentation (BMI) thimble tubes and bullet plugs. Because the applicant's Bottom-Mounted Instrumentation Thimble Tube Inspection Program does not mention cracking, the staff requested that the applicant confirm that cracking for BMI thimble tubes is a credible degradation mechanism requiring aging management and revise the program, if necessary, to include inspection for cracking due to SCC. The staff addressed this issue in RAI B.1.5-1.

The applicant responded in its letter dated August 19, 2004, that the Water Chemistry Control and Inservice Inspection Programs manage cracking caused by SCC. The applicant did not address whether cracking is a credible degradation mechanism for BMI thimble tubes. GALL Report line item B2.6-c lists only "lost of material/wear" as the aging effect for thimble tubes. Therefore, considering cracking for thimble tubes is not consistent with the GALL Report. The staff finds that, compared to the loss of material in thimble tubes due to wear, SCC is insignificant. The staff based its determination on the following:

- SCC requires a tensile stress to grow while the thimble tubes under external RCP give compressive stresses.
- NRC IN 87-44 and Bulletin 88-09 attribute FIV as the cause for BMI thimble tube thinning and do not mention any indication of SCC.

Hence, the staff concludes that it is prudent and acceptable for the applicant to use the Water Chemistry Control and Inservice Inspection Programs to manage cracking in BMI thimble tubes due to SCC. Therefore, the staff's concern described in RAI B.1.5-1 is resolved.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cracking in stainless steel BMI thimble tubes under a borated water environment, as recommended in the GALL report. Since the applicant's AMR evaluation exceeds the GALL Report requirements, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Miscellaneous Items - Reduction in Fracture Toughness of Shell Rings and Loss of Mechanical Closure Integrity for Closure Studs, Nuts, and Washers Exposed Externally to Potentially Leaking Borated Water

Summary of Technical Information in the Application

The applicant has identified in LRA Table 3.1.2-1 that reduction in fracture toughness is an AERM for the beltline region of the shell rings that are made of LAS internally clad with stainless steel or nickel-based alloy and are exposed to the borated water environment. The applicant credited the Reactor Vessel Integrity Program and the TLAA regarding RPV neutron embrittlement with the management of reduction in fracture toughness for RPV shell rings. Further, the applicant identified in LRA Table 3.1.2-1 that the loss of mechanical closure integrity is an AERM for closure studs, nuts, and washers which are made of LAS and are exposed externally to potentially leaking borated water. The applicant credited Inservice Inspection and the Boric Acid Corrosion Prevention Programs with the management of the loss of mechanical closure integrity for closure studs, nuts, and washers.

Staff Evaluation

The applicant identified reduction in fracture toughness for the beltline region of the shell rings to be an AERM, as indicated in LRA Table 3.1.2-1. The applicant credited the TLAA regarding reactor vessel neutron embrittlement (SER Section 4.2) with the management of reduction of fracture toughness of reactor vessel beltline materials resulting from neutron embrittlement. This is acceptable because, as discussed in Section 4.2, the TLAA evaluates and determines the amount of toughness that is appropriate for the CNP reactor vessel beltline materials to experience through the end of the period of extended operation in terms of the three parameters specified in the rules on fracture toughness requirements—pressurized thermal shock (PTS) reference temperatures, RT_{PTS} (10 CFR 50.61), Charpy upper-shelf energy (USE) values (Appendix G to 10 CFR Part 50) and similar RTs, and nil ductility transition RT (RT_{NDT}), used in P-T limit calculations (Appendix B to 10 CFR Part 50). The first parameter applies to PWRs; the remaining two parameters apply to both BWRs and PWRs. Reactor Vessel Integrity Program will provide valid RPV embrittlement information based on surveillance capsule data to supplement the prediction of these three parameters.

RAI 3.1-10

The applicant identified the loss of mechanical closure integrity to be an AERM for reactor vessel closure studs, nuts, and washers, as indicated in LRA Table 3.1.2-1, and credited the Inservice Inspection (SER Section 3.0.3.1) and Boric Acid Corrosion Prevention (SER Section 3.0.3.2.1) Programs with the management of this aging effect. The staff's AMR review of GALL Report line items IV.A2.1-a, -c, -d, and -e for stud assembly confirms that the loss of mechanical closure integrity is not listed as an aging mechanism, and GALL AMP XI.M3, "Reactor Head Closure Studs," is the recommended AMP for managing cracking, loss of material, and wear for these components. Because cracking, loss of material, and wear will lead to a loss of mechanical closure integrity of reactor vessel closure studs, nuts, and washers, the staff still references GALL AMP XI.M3 to conduct the evaluation. The main objective of this GALL program is to provide timely detection of cracks, loss of material, and leakage associated with closure studs, nuts, and washers, using ISIs in accordance with ASME Code, Section XI, Subsection IWB, Table IWB 2500-1. The applicant does not have a specific AMP similar to

GALL AMP XI.M3. However, the applicant captured the primary elements of GALL AMP XI.M3 through its use of the Inservice Inspection and Boric Acid Corrosion Prevention Programs. To fully justify not having an AMP similar to GALL AMP XI.M3 for CNP, the staff requested the applicant to address another element in GALL AMP XI.M3 (i.e., preventive measures to mitigate cracking for these components). The staff addressed this issue in RAI 3.1-10.

The applicant responded in the letter dated August 11, 2004, that preventive measures have been incorporated to manage cracking of the reactor vessel closure bolting. These measures include an application of a magnesium phosphate coating to the bearing surfaces of the reactor vessel closure bolting during fabrication and the use of a lubricant (neolube) during tensioning of the bolting, which are consistent with the preventive measures of RG 1.65, "Material and Inspection for Reactor Vessel Closure Studs," specified in GALL Program XI.M3. With this additional information, the staff concludes that the essential elements of GALL AMP XI.M3 have been captured by the applicant through its use of the Inservice Inspection and Boric Acid Corrosion Prevention Programs. Therefore, having an AMP similar to GALL AMP XI.M3 is not necessary, and RAI 3.1-10 is closed.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the reduction in fracture toughness of shell rings and the loss of mechanical closure integrity for closure studs, nuts, and washers exposed externally to potentially leaking borated water, as recommended in the GALL Report. Since the applicant's AMR results are consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Reactor Vessel and CRDM Pressure Boundaries Summary of Aging Management

The staff reviewed Table 3.1.2-1 of the LRA, which summarizes the results of AMR evaluations in the SRP-LR for the reactor vessel and CRDM pressure boundary component groups.

In the LRA, the applicant stated that the GALL Report does not address the loss of material from components with stainless steel and nickel-based alloy cladding in borated water for bottom and upper head, shell rings (including the nozzle course), and vessel and closure head flanges, as well as inlet and outlet nozzles. The applicant proposed to control this aging mechanism using the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.10. Section 3.0.3.2.15 of this SER documents the staff's evaluation of this program.

In LRA Table 3.1.2-1, for each of these same component and material combinations, the applicant also manages cracking using the Water Chemistry Control Program, the Inservice Inspection Program, and a plant-specific program, such as the Alloy 600 Aging Management Program (CNP AMP B.1.1). The staff accepted the applicant's Inservice Inspection Program and documents its evaluation of this AMP in SER Section 3.0.3.1. SER Section 3.0.3.3.1 summarizes the staff's evaluation of the Alloy 600 Aging Management Program. The applicant manages cracking in a manner consistent with the GALL Report.

Because the applicant manages the cracking of stainless steel and nickel-based alloy components through its Water Chemistry Control and Inservice Inspection Programs, and on the basis of industry experience that the effects of general and crevice corrosion, as well as pitting, on stainless steel components in chemically treated, borated water are not significant, the staff finds that the management of the loss of material aging effect using water chemistry control is sufficient for stainless steel cladding. This conclusion also applies to loss of material from nickel-alloy cladding in chemically treated, borated water.

In the LRA, the applicant stated that the cracking of stainless steel cladding of the weld buildup support pads caused by external-ambient conditions is an aging effect managed under CNP AMP B.1.14, "Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD." Section 3.0.3.1 of this SER documents the staff's evaluation of this AMP. The GALL Report does not identify this aging effect for this material, environment, and component combination. The staff finds the applicant's identification of cracking as an applicable effect for these components to be acceptable and its Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program to be appropriate for managing this aging effect.

In the LRA, the applicant stated that the GALL Report does not address the loss of material from components in treated, borated water as an aging effect for nickel-based alloy and stainless steel. The applicant proposed to use the Water Chemistry Control Program to manage this aging effect for nickel-based alloy CRDM nozzles, in-core instrumentation nozzles, the vent line nozzle and elbow, and Unit 1 flange leak tubes. The same program will be used for stainless steel Unit 1 inlet and outlet nozzle safe ends CRDM housing adapters, in-core instrumentation nozzle safe ends and housing cap, in-core instrumentation nozzle safe ends, the BMI thimble guide tubes and bullet plugs, the thimble seal table, the vent line safe end, CRDM housing, core exit thermocouple nozzle assembly, holddown nut, compression collar, lockwasher, CRDM housing cap, and Unit 2 flange leak tubes.

In LRA Table 3.1.2-1, for each of these same component and material combinations, the applicant also manages cracking using the Water Chemistry Control Program, the Inservice Inspection Program, and a plant-specific program, such as the Alloy 600 Aging Management Program (CNP AMP B.1.1) or the Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program (CNP AMP B.1.9). The staff accepted the applicant's Inservice Inspection Program and documents its evaluation of this AMP in SER Section 3.0.3.1. The staff reviewed the Alloy 600 Aging Management and Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Programs. SER Sections 3.0.3.3.1 and 3.0.3.2.3, respectively present the results of this review. The staff finds that the applicant manages cracking in a manner consistent with the GALL Report.

The staff finds that the management of this aging effect using water chemistry control is sufficient on the basis (1) that the applicant's management of cracking of nickel-based alloy and stainless steel components in treated, borated water is consistent with the GALL Report, and (2) industry experience that the effects of general corrosion, crevice corrosion, and pitting, on stainless steel components in chemically treated, borated water are not significant. The staff has reached a similar conclusion for the loss of material from nickel-alloy components in chemically treated, borated water.

In the LRA, the applicant stated that it manages the loss of material for nickel-based alloy in borated water for core support lugs using the Water Chemistry Control Program, in addition to the Inservice Inspection Program as specified in the GALL Report. The staff finds the combination of this preventive/mitigative program with an inspection program to be an acceptable way to manage this aging effect.

During the audit and review, the staff noted that the applicant handled cracking of stainless steel alloy in treated, borated water in a manner consistent with the GALL Report for the core exit thermocouple nozzle assembly, but the head port adapter (holddown nut, compression collar, and lockwasher) is not exposed to the same environment. By letter dated April 23, 2004, the applicant provided the following response to the audit question:

> The stainless steel thermocouple nozzle assembly head port adapter is exposed to an internal environment of borated water and an external-ambient environment. The applicable aging effects include cracking and loss of material, which will be managed by the Inservice Inspection Program and the Water Chemistry Control Program throughout the period of extended operation.
>
> The thermocouple nozzle assembly head port adapter is attached to a CRDM head nozzle adapter by means of a threaded connection and a canopy seal weld. The canopy seal weld is exposed to an external-ambient environment. The applicable aging effect of the canopy seal weld is cracking, which is managed by the Boric Acid Corrosion Prevention Program.

The staff finds that the applicable aging effects are consistent with the GALL Report. Therefore, the response is acceptable.

RAI 3.1.2-1

In Table 3.1.2-1, the applicant identified cracking as an AERM for Reactor Vessel and CRDM Pressure Boundary components manufactured from nickel-based alloys and stainless steel alloys exposed to treated (borated) water environments. The applicant identified the flange leak tubes as the components that are subject to cracking. The applicant stated that the flange leak tubes in Unit 1 are made from nickel-based alloys and the flange leak tubes from Unit 2 are made from stainless steel. The Water Chemistry Control, Inservice Inspection, and Alloy 600 Aging Management (Unit 1 only) Programs manage the aging effect. The applicant stated that the component, material, environment, aging effect and aging management program is not consistent with the GALL Report.

The GALL Report item A2.1-f states that a plant specific AMP must be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC in the vessel flange leak detection line. The applicant did not identify how SCC will be managed in the stainless steel flange leak tubes. Therefore, in RAI 3.1.2-1 dated July 28, 2004, the staff requested the following action of the applicant:

> The staff requests that the applicant identify the aging management program that will be used to mitigate or detect crack initiation and growth due to SCC in the Stainless Steel vessel flange leak tubes. Included should be a discussion about corrective actions involving repair/replacement.

In its supplemental letter dated August 11, 2004, the applicant's response to RAI 3.1.2-1, stated that the Unit 2 stainless steel flange leak tubes listed in LRA Table 3.1.2-1 are contained entirely within the reactor vessel flange. Stainless steel piping is attached to these tubes, external to the vessel. The category of RCS stainless steel piping of less than NPS 4", as listed in LRA Table 3.1.2-3, includes this piping. The applicant will manage SCC aging effects on the stainless steel reactor vessel flange leak detection tubes and external piping using a combination of the Primary and Secondary Water Chemistry Control Program; the Inservice Inspection-ASME Section XI, Subsection IWB, IWC, and IWD Program; and, for the piping, the Small Bore Piping Program. The applicant stated that if required, evaluation, repair, and replacement are performed in accordance with applicable ASME Code, Section XI requirements.

Based upon the above information, the staff finds the applicant's management of cracking in the vessel flange leak tubes to be appropriate. Therefore, the staff's concern described in RAI 3.1.2-1 has been resolved.

Conclusion

On the basis of its audit and review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the reactor vessel and CRDM pressure boundary components so that the component intended functions can 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.1.2.3.2 Reactor Vessel Internals

Summary of Technical Information in the Application

In Section 3.1.2.1.2 of the LRA, the applicant identified the materials, environments, and AERMs for the RVI. The applicant identified the following programs that manage the AERMs for the RVI and associated pressure boundary components:

- Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program
- Reactor Vessel Internals Cast Austenitic Stainless Steel Program
- Water Control Chemistry Program
- Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program

In Table 3.1.2-2 of the LRA, the applicant provided a summary of AMRs for the reactor vessel internals and associated pressure boundary components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited for managing them for the RVI components. The staff also reviewed the applicable UFSAR Supplements to ensure that the AMPs are adequately described.

Cracking and Loss of Mechanical Closure Integrity in Selected Stainless Steel Reactor Vessel Internals

Summary of Technical Information in the Application

The applicant identified that cracking is an AERM for the following stainless steel components that are exposed to the borated water environment, as indicated in LRA Table 3.1.2-2:

- core baffle bolts and core former bolts
- upper support plate (Unit 1 only)
- deep beam sections
- upper support columns (excluding CASS or CASS components)
- support column bolts

Staff Evaluation

All of the components listed above, except for core baffle and core former (baffle/former) bolts, are considered to be upper core support structure components. As indicated in the component listing above, this AMR does not include the CASS components in upper support columns. The applicant credited the Water Chemistry Control (SER Section 3.0.3.2.15), Inservice Inspection (SER Section 3.0.3.1), and Reactor Vessel Internals (SER Section 3.0.3.1) Programs with the management of cracking in these components.

The applicant identified that cracking is an applicable aging effect for the above listed stainless steel RVI that are exposed to the borated water environment and categorized the AMR for these components as not consistent with the corresponding GALL Report line item. GALL Report line item IV.B2.4-c for baffle/former bolts recommends a plant-specific program with appropriate augmented visual inspections to manage cracking in this component; GALL line items (IV.B2.1-a, IV.B2.1-e, IV.B2.1-i, IV.B2.5-e, and IV.B2.5-k) for the upper core support structure components listed above recommend the Reactor Vessel Internals and Water Chemistry Control Programs to manage cracking in them. The applicant provided information beyond that required by the GALL Report for managing cracking in these components by crediting the plant-specific AMP recommended by the GALL Report for the baffle/former bolts and the AMPs recommended by the GALL Report for the upper core support structure components with the management of cracking in all the components listed above. As discussed in Section 3.0.3.1 of this document, the applicant's Reactor Vessel Internals Program contains this plant-specific program for baffle/former bolts. Since the staff has accepted the Reactor Vessel Internals Program, the AMP for managing cracking for all components listed above, as indicated in SER Section 3.0.3.1, this specific AMR review is also acceptable. The Water Chemistry Control Program and Inservice Inspection Program will supplement Reactor Vessel Internals Program in managing cracking in these components.

The applicant credited the Inservice Inspection and Reactor Vessel Internals Programs with the management of another aging effect, the loss of mechanical closure integrity. GALL Report line item IV.B2.4-h recommends the use of the same plant-specific AMP discussed above for managing cracking to manage the loss of preload/stress relaxation of baffle/former bolts. The staff considers loss of mechanical closure integrity to be equivalent to the loss of preload/stress relaxation. Therefore, based on the acceptance of the Reactor Vessel Internals Program, the staff determines that using this AMP for managing the loss of mechanical closure integrity of baffle/former bolts is appropriate. The Inservice Inspection Program will supplement the Reactor Vessel Internals Program in managing the loss of mechanical closure integrity of baffle/former bolts.

For the upper core support structure components listed above, GALL Report line items IV.B2.1-k and IV.B2.5-h recommend the use of the Inservice Inspection Program and a "loose part monitoring" program to manage the loss of mechanical closure integrity. The staff reviewed GALL AMP XI.M14, "Loose Part Monitoring," and LRA Table B-1 regarding justification for not having a CNP AMP similar to GALL AMP XI.M14. Since cracking is an early indication of loose part generation, the staff concludes that adequate management of cracking in these components through Reactor Vessel Internals Program could reduce the probability of having loose parts from these components. Therefore, the staff accepts this CNP AMR for managing the loss of mechanical closure integrity of these components. The Inservice Inspection Program will supplement the Reactor Vessel Internals Program in managing the loss of mechanical closure integrity of the upper core support structure components.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cracking and the loss of mechanical closure integrity in the selected stainless steel RVI components listed above, as recommended in the GALL Report. Since the applicant's AMR results are either consistent with or exceed the GALL Report requirements, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Reactor Vessel Internals Summary of Aging Management

In the LRA, the applicant stated that the GALL Report does not address the loss of material for stainless steel (including CASS) in treated, borated water. This aging effect is considered for the following components:

- core barrel, flange, outlet nozzle, and fasteners
- core former plates, baffle plates, baffle bolts, former bolts, and lower plate
- lower support columns
- diffuser plate
- lower support plate
- lower core plate support column cap
- secondary core support assembly
- thermal shield
- upper support plate (Unit 1)
- deep beam sections
- upper support columns
- support column bolts
- upper core support column mixing device
- upper core support column orifice base
- upper support plate (Unit 2)
- upper core plate and plate alignment pins
- lower support radial keys
- holddown spring
- guide tube assemblies

- upper system thermocouples
- lower system flux thimbles

The applicant stated that the GALL Report does not address loss of material for nickel-based alloy in treated, borated water. This aging effect is considered for clevis insert fasteners. The applicant proposed to manage loss of material for this material-environment combination using only its Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1). Section 3.0.3.2.15 of this SER documents the staff's evaluation of this program.

In LRA Table 3.1.2-2, for each of these same component and material combinations, the applicant also manages cracking using the Water Chemistry Control and Inservice Inspection Programs and a plant-specific program, such as CNP AMP B.1.28, "Reactor Vessel Internals Cast Austenitic Stainless Steel," or CNP AMP B.1.27, "Reactor Vessel Internals Plates, Forgings, Welds, and Bolting." The staff accepted the applicant's Inservice Inspection Program and documents its evaluation of this AMP in Section 3.0.3.1 of this SER. The staff reviewed Reactor Vessel Internals Cast Austenitic Stainless Steel Program and documents its evaluation in Section 3.0.3.1 of this SER. The staff reviewed the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program and summarizes the results of its review in Section 3.0.3.1 of the SER. The staff finds that the applicant manages cracking in a manner consistent with the GALL Report.

The staff finds that management of this aging effect using water chemistry control is sufficient on the basis (1) that cracking of stainless steel (including CASS) and nickel-based alloy components in treated, borated water is managed consistent with the GALL Report, and (2) of industry experience that the effects of general corrosion, crevice corrosion, and pitting on components made of stainless steel (including CASS) in chemically treated, borated water are not significant. The staff reached the same conclusion for the loss of material from nickel-alloy components in chemically treated, borated water.

In the LRA, the applicant stated that it manages the aging effects of the nickel-based alloy clevis insert block, control rod guide tube pin, and fuel assembly guide pin using the Inservice Inspection and Water Chemistry Control Programs. On the basis that the GALL Report suggests managing aging effects for these components using ISI, the staff finds the applicant's approach to be acceptable.

Conclusion

On the basis of its audit and review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the RVI components so that the component intended functions can 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.1.2.3.3 Class 1 Piping, Valves, and Reactor Coolant Pumps

Summary of Technical Information in the Application

In Section 3.1.2.1.3 of the LRA, the applicant identified the materials, environments, and AERMs for Class 1 piping, valves and RCPs. The applicant identified the following programs that manage the AERM for the Class 1 piping, valves, and RCPs and associated pressure boundary components:

- Water Chemistry Control Program
- Inservice Inspection - ASME Section XI, Subsection IWB, IWC, and IWD Program
- Cast Austenitic Stainless Steel Evaluation Program
- Small Bore Piping Program
- Boric Acid Corrosion Prevention Program
- Bolting and Torquing Activities Program

In Table 3.1.2-3 of the LRA, the applicant provided a summary of AMRs for the Class 1 piping, valves, and RCPs and associated pressure boundary components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects, and the AMPs credited for managing them, in Class 1 piping of the RCS. The staff also reviewed the applicable UFSAR Supplements to ensure that the AMP descriptions are adequate.

Aging Effects

In Section 3.1 of the LRA, the applicant performed a review of information generated from industry experience and NRC generic communications relative to the RCS components to ensure that the AERMs for a specific material-environment combination are the only aging effects of concern for CNP.

The LRA identified the following applicable aging effects for the Class 1 piping, valves, and RCPs of the RCS:

- cracking
- reduction in fracture toughness
- loss of material
- loss of mechanical closure integrity
- fouling

Table 3.1.2-3 of the LRA identifies the components in the RCS Class 1 piping that are subject to an AMR. This table also includes components which the GALL Report evaluates. The components that the applicant indicated are consistent with the GALL Report need no additional evaluation because the staff accepts the GALL Report's conclusions with respect to those components and programs that do not require further evaluation.

Table 3.1.2-3 also includes components tha the GALL Report does not evaluate. The table identifies the aging effects, materials, environments, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and finds that the applicant has identified the applicable aging effects.

On the basis of the applicant's review of industry experience and NRC generic communication relative to the RCS components, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the Class 1 piping of the RCS.

Aging Management Programs

The applicant credited the following AMPs to manage the aging effects described above for the Class 1 piping, valves, and RCPs of the RCS:

- Water Chemistry Control Program
- Inservice Inspection—ASME Section IX, Subsection IWB, IWC, and IWD Program
- Cast Austenitic Stainless Steel Evaluation Program
- Small Bore Piping Program
- Boric Acid Corrosion Prevention Program
- Bolting and Torquing Activities Program

The staff reviewed LRA Table 3.1.2-3, which summarizes the results of AMR evaluations in the SRP-LR for the Class 1 piping, valves, and RCP component groups. The staff finds that the programs proposed for managing the aging effects for the component types in this system are consistent with the GALL Report.

In the LRA, the applicant stated that it addresses the loss of material for CASS in treated, borated water using the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) and the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14) for the hot- and cold-leg pipe and fittings, crossover-leg pipe and fittings, Class 1 valve bodies and bonnets (NPS 2.5" and NPS less than 2"), RCP casing, main closure flange, pressurizer surge line, piping and fitting (including blind flanges) (NPS 4" and NPS less than 4"), branch nozzles (NPS 4" and NPS less than 4"), thermal sleeves, orifices, and Class 1 valve bodies and bonnets (NPS 2.5" and NPS less than 2"). Sections 3.0.3.2.15 and 3.0.3.1 of this SER, respectively, document the staff's evaluation of these two programs. This is consistent with the recommendations in the GALL Report for managing other components of the same material in a similar environment. On that basis, the staff finds this approach to be acceptable.

In the LRA, the applicant stated that it will manage the loss of material from the stainless steel thermal barrier heat exchanger in treated water using the Water Chemistry Control Program. On the basis of industry experience that the effects of general and crevice corrosion, as well as pitting, on components made of stainless steel in chemically treated water and treated, borated water are not significant, the staff finds that management of this aging effect using water chemistry control is sufficient.

In the LRA, the applicant stated that it will manage cracking of LAS and stainless steel bolting material using the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Section 3.0.3.1 of this SER documents the staff's evaluation of this program. To manage cracking of the bolting material for valves and blind flanges, as well as main flange bolts, the applicant proposed to use the Inservice Inspection Program. Although a the applicant cited a precedent, the staff was unable to confirm its applicability. For the component referenced, the GALL Report recommends a program consistent with GALL AMP XI.M18, which invokes the guidelines of NUREG-1339 to prevent and mitigate bolting degradation.

RAI 3.1.3-1

By letter dated August 20, 2004,in RAI 3.1.3-1, the staff requested that the applicant explain its rationale for excluding bolting material for valves and blind flanges, as well as main flange bolts, from the scope of its Bolting and Torquing Activities Program (CNP AMP B.1.2) or to confirm that it is managed using this program. In a letter dated September 2, 2004, in response to RAI 3.1.3-1, the applicant stated that it credited the Bolting and Torquing Activities Program for managing the loss of mechanical closure integrity for the valve and pump bolting listed in LRA Table 3.1.2-3. The applicant also stated that the aging effect of cracking is listed separately for these same components, and is managed by the Inservice Inspection Program, which is more appropriate for closure bolting in Class I systems.

On the basis of its review of the applicant's response to RAI 3.1.3-1, the staff finds that the applicant will adequately manage all aging effects of bolting material for valve and blind flanges and main flange bolts by use of the Inservice Inspection and Bolting and Torquing Activities Programs. The staff further concludes that the applicant will manage these aging effects adequately during the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, the staff's concern described in RAI 3.1.3-1 is resolved.

In Table 3.1.2-2, the applicant identified that cracking is an AERM for Class 1 piping components manufactured from CASS and stainless steel that are exposed to borated water environments. The applicant identified the hot-leg pipe and fittings, cold-leg pipe and fittings, crossover-leg pipe and fittings, and pressurizer surge line as subject to cracking, and the AMP as the leak before break (LBB) TLAA. The applicant stated that it performed an LBB analysis for the CNP RCS primary loop and the pressurizer surge line. The analyses considered the thermal aging of CASS piping and the fatigue transients that drive the flaw growth over the operating life of the plant. The analyses indicated that the properties for the CASS piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation. The applicant also indicated that the results of the RCS transient cycle definition review determined that the RCS design transients originally defined for 40 years are acceptable for 60 years of operation. The applicant also stated that, in addition to the LBB TLAA, it will use the Water Chemistry Control and Inservice Inspection Programs to manage cracking. The staff concludes that the LBB TLAA, combined with the Water Chemistry Control and Inservice Inspection Programs, will effectively manage cracking in CASS components.

On the basis of its review, the staff finds the applicant's management of cracking for Class 1 piping components manufactured from CASS and stainless steel exposed to borated water environments is acceptable.

In Table 3.1.2-2, the applicant identified that the loss of material is an AERM for Class 1 valve components manufactured from LAS and exposed to an external-ambient environment. The applicant manages this aging effect using the Boric Acid Corrosion Prevention Program. The applicant identified the components as Class 1 valve bodies and bonnets less than 2.5 inches and bolting material for valves and blind flanges. The aging effect for this component is not addressed by the GALL Report; however, the AMP is consistent with GALL AMP XI.M10. The aging effect for the bolting material for valves and blind flanges is consistent with the GALL Report for this component, environment, and material, and the AMP is consistent with GALL AMP XI.M10. The applicant stated that the Boric Acid Corrosion Prevention Program relies on the implementation of recommendations in NRC GL 88-05 to monitor the condition of ferritic steel components onto which borated reactor water may leak. The applicant stated that periodic visual inspection of adjacent SCs and supports for evidence of leakage and corrosion is an element of the GL 88-05 monitoring program.

RAI 3.1.2-2

The applicant did not identify which aging mechanisms could lead to loss of material in the above components that are fabricated from alloy steel or carbon steel, although the AMP credited with aging management appears to imply that the applicant only considered potential leakage of the borated coolant as a mechanism that could induce loss of material from the external surfaces of these components. Alloy steel and carbon steel components may also be susceptible to general corrosion in atmospheric environments, if the atmospheres are damp, moist, or humid. Therefore, in RAI 3.1.2-2, dated July 28, 2004, the staff requested the following action of the applicant:

> The staff requests that the applicant identify the aging mechanism that CNP has determined are capable of inducing loss of material in alloy steel or carbon steel of the above components that are exposed externally to the inside environments. In addition, the applicant is requested to describe the inside environment and whether the applicant is managing the water vapor content in the inside environment to low humidity levels. The staff seeks further clarification whether the applicant considers loss of material due to general corrosion is an applicable aging effect for external surfaces of alloy steel or carbon steel components that are exposed to the inside environment. If not, the applicant is requested to provide technical justification why CNP does not consider general corrosion to be an aging mechanism that needs management in the external surfaces of alloy steel or carbon steel components during the extended periods of operation.

In its supplemental letter dated August 11, 2004, the applicant provided the following response to RAI 3.1.2-2:

> Containment temperature is maintained below 120 degrees Fahrenheit (°F) in the containment lower compartment and below 100°F in the containment upper compartment; humidity is not managed inside containment. No Class 1 valves or low alloy steel materials are listed in LRA Table 3.1.2-2; they are, however, listed in LRA Table 3.1.2-3. The representative component types listed include selected low alloy Class 1 valve bonnets and low alloy steel bolting associated with valves blind flanges. Low alloy steel components such as ferritic valve bonnets and ferritic bolting are susceptible to loss of material due to boric acid corrosion that might result from system leakage onto these components. Because the valve components are inside containment, no significant general corrosion is expected. Under the Boric Acid Corrosion Preventive Program

described in LRA Section B.1.4, evidence of moisture that could cause boric acid corrosion (or general corrosion) on ferritic surfaces is detected by visual inspection and evaluated by engineering to determine the leakage source, extent of degradation, and required corrective actions. Therefore, loss of material of low alloy steel valve bonnets and low alloy steel closure bolting will be managed by the Boric Acid Corrosion Preventive Program for the period of extended operation.

Based upon the above information, the staff finds the applicant has provided an acceptable AMP for managing the loss of material in alloy steel or carbon steel components that are exposed externally to the inside environments. Therefore, the staff's concern described in RAI 3.1.2-2 is resolved.

In LRA Table 3.1.2-3, the applicant identified that a loss of mechanical closure integrity is an AERM for Class 1 valve components manufactured from LAS and stainless steel material and exposed to an external-ambient environment. The Inservice Inspection, Bolting and Torquing Activities, and Boric Acid Corrosion Prevention Programs manage this aging effect. The applicant identified the components as bolting material for valves and blind flanges. The aging effect, material, and environment combination is consistent with the GALL Report, but the report credits a different AMP. Item IV.C2.4-g of the GALL Report credits the Boric Acid Corrosion Prevention Program, and requires no further evaluation. The staff concludes that the Inservice Inspection, Bolting and Torquing Activities, and Boric Acid Corrosion Prevention Programs will effectively manage the loss of mechanical closure integrity for Class 1 valve components manufactured from LAS and stainless steel.

Based upon the above information, the staff finds that the applicant has provided an acceptable AMP for managing the loss of mechanical closure integrity for Class 1 valve components manufactured from LAS and stainless steel that are exposed to an external ambient environment.

The applicant identified in LRA Table 3.1.2-3 that cracking is an AERM for RCPs manufactured from CASS and exposed to a treated (borated) water environment. The applicant identified the components as casings and the AMP as the ASME Code Case N-481 Evaluation TLAA. The applicant stated that the aging effect identified is not in the GALL Report for this component, material, and environment combination. The applicant stated in the TLAA that it generically evaluated a demonstration of compliance of the primary loop pump casings with ASME Code Case N-481 for all Westinghouse plants in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems." The applicant conducted a CNP-specific Code Case N-481 evaluation in WCAP-13128, "Demonstration of Compliance of the Primary Loop Pump Casings of D.C. Cook Units 1 and 2 to ASME Code Case N-481." The analysis considered thermal aging and fatigue crack growth to be influenced by time and relied on fully aged stainless steel material properties. The analyses concluded that the properties for the cast stainless casing material are acceptable because they will not degrade below the fully aged properties during the extended period of operation. The applicant stated that the Fatigue Monitoring Program, which is discussed in Appendix B to the LRA, monitors thermal fatigue design transients for the period of extended operation. The applicant further stated that, in addition to the ASME Code Case N-481 Evaluation TLAA, the Water Chemistry Control and Inservice Inspection Programs are also included to monitor and detect/control cracking in the RCP casings. The staff concludes that the ASME Code Case N-481 Evaluation TLAA, combined with the Water Chemistry Control and Inservice Inspection Programs, will effectively manage cracking in RCP components manufactured from CASS.

On the basis of the above information, the staff finds the applicant has provided an acceptable AMP for RCPs manufactured from CASS and exposed to a treated (borated) water environment.

In LRA Table 3.1.2-2, the applicant identified that the loss of material is an AERM for RCP components manufactured from LAS and exposed to an external-ambient environment. The applicant manages this aging effect using the Boric Acid Corrosion Prevention Program. The applicant identified the components requiring management as the main flange bolts. The GALL Report does not identify the aging effect for this component, however, the applicant's AMP is consistent with GALL AMP XI.M10. The aging effect for the main flange bolts is consistent with the GALL Report for this component, environment, and material combination, and the AMP is consistent with GALL AMP XI.M10. The applicant stated that the Boric Acid Corrosion Prevention Program relies on the implementation of recommendations in NRC GL 88-05 to monitor the condition of ferritic steel components onto which borated reactor water may leak. The applicant stated that periodic visual inspection of adjacent SCs and supports for evidence of leakage and corrosion is an element of the GL 88-05 monitoring program.

RAI 3.1.2-3

The applicant did not identify which aging mechanisms could lead to loss of material in the above components that are fabricated from alloy steel or carbon steel, although the AMP credited with aging management appears to imply that the applicant only considers potential leakage of the borated coolant as a mechanism that could induce loss of material from the external surfaces of these components. Alloy steel and carbon steel components may also be susceptible to general corrosion in atmospheric environments, if the atmospheres are damp, moist, or humid. Therefore, in RAI 3.1.2-3, dated July 28, 2004, the staff requested the following action of the applicant:

> The staff requests that the applicant identify the aging mechanism that CNP has determined are capable of inducing loss of material in alloy steel or carbon steel of the above components that are exposed externally to the inside environments. In addition, the applicant is requested to describe the inside environment and whether the applicant is managing the water vapor content in the inside environment to low humidity levels. The staff seeks further clarification whether the applicant considers loss of material due to general corrosion is an applicable aging effect for external surfaces of alloy steel or carbon steel components that are exposed to the inside environment. If not, the applicant is requested to provide technical justification why CNP does not consider general corrosion to be an aging mechanism that needs management in the external surfaces of alloy steel or carbon steel components during the extended periods of operation.

In its supplemental letter dated August 11, 2004, the applicant's response to RAI 3.1.2-3 stated that the containment temperature is maintained below 49 °C (120 °F) in the containment lower compartment and below 38 °C (100 °F) in the containment upper compartment; however, humidity is not managed inside containment. The applicant stated that no reactor coolant pump

(RCP) or LAS materials are listed in LRA Table 3.1.2-2, but the LAS RCP main flange bolting is listed. LAS components, such as bolting, are susceptible to he loss of material due to boric acid corrosion that might result from system leakage onto these components. Since the components are inside containment, no significant general corrosion is expected. The applicant stated that under the Boric Acid Corrosion Prevention Program described in LRA Section B.1.4, evidence of moisture that could cause boric acid corrosion (or general corrosion) on ferritic surfaces is detected by visual inspection and evaluated by engineering to determine the leakage source, extent of degradation, and required corrective actions. The applicant indicated that the Boric Acid Corrosion Prevention Program will manage the loss of material of LAS RCP main flange bolting for the period of extended operation.

Based upon the above information, the staff finds that the applicant has provided an acceptable AMP for managing loss of material of LAS RCP main flange bolting for the period of extended operation. Therefore, the staff's concern described in RAI 3.1.2-3 is resolved.

In LRA Table 3.1.2-3 the applicant identified that a loss of mechanical closure integrity is an AERM for RCP components manufactured from LAS material and exposed to an external-ambient environment. The applicant manages this aging effect using the Inservice Inspection, Bolting and Torquing Activities, and Boric Acid Corrosion Prevention Programs. The applicant identified the components requiring management as the main flange bolts. The aging effect, material, and environment combination is consistent with the GALL Report, but the report credits a different AMP. Item IV.C2.4-g of the GALL Report credits the Boric Acid Corrosion Prevention Program and requires no further evaluation. The staff concludes that the Inservice Inspection, Bolting and Torquing Activities, and the Boric Acid Corrosion Prevention Programs will effectively manage the loss of mechanical closure integrity for Class 1 valve components manufactured from LAS.

On the basis of the above information, the staff finds that the applicant has provided an acceptable aging management program for managing loss of mechanical closure integrity for Class 1 valve components manufactured from LAS.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited for managing them for the ASME Code Class 1 piping, valves, and RCPs so 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.1.2.3.4 Pressurizer

Summary of Technical Information in the Application

In Section 3.1.2.1.4 of the LRA, the applicant identified the materials, environments, and AERMs for the pressurizer. The applicant identified the following programs that manage the AERMs for the pressurizer and associated pressure boundary components:

- Water Chemistry Control Program
- Pressurizer Examinations Program
- Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program
- Boric Acid Corrosion Prevention Program
- Alloy 600 Aging Management Program
- Bolting and Torquing Activities Program

In Table 3.1.2-4 of the LRA, the applicant provided a summary of AMRs for the pressurizer and associated pressure boundary components, and identified which AMRs it considered to be not consistent with the GALL Report. These components include the pressurizer lower head, shell, and upper shell; surge, spray, relief, and safety nozzles and their thermal sleeves; and a variety of support plates, brackets and lugs.

Staff Evaluation

This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPS credited for managing them for the pressurizer components. The staff also reviewed the applicable UFSAR Supplements to ensure that the AMPs are adequately described.

Loss of Material in Carbon Steel, Low Alloy Steel, and Low Alloy Steel Internally Clad with Stainless Steel or Nickel Based Alloy (Weld Buttering) for Selected Pressurizer Components Exposed Externally to Potentially Leaking Borated Water

Summary of Technical Information in the Application

The applicant identified in LRA Table 3.1.2-4 that loss of material is an AERM for the following pressurizer components which are made of carbon steel, LAS, and LAS clad with stainless steel or nickel-based alloy and which are potentially exposed externally to leaking borated water:

- lower head, shell, and upper head (LAS clad with stainless steel)
- surge, spray, relief, and safety nozzles (LAS clad with stainless steel and nickel-based alloy)
- support skirt and flange (carbon steel)
- seismic lugs (LAS)
- valve support bracket lugs (carbon steel)
- manway forging (LAS clad with stainless steel)
- manway cover and its bolts/studs (LAS)

The applicant credited the Boric Acid Corrosion Prevention Program (LRA Section B.1.4) with the management of the loss of material in these components.

Staff Evaluation

The applicant identified the loss of material as an applicable aging effect for carbon steel, LAS, and LAS clad with stainless steel or nickel-based alloy pressurizer components that are exposed to the ambient environment. It characterized the AMR for managing these components as not consistent with the GALL Report line item or not consistent with the GALL Report line item except for the component itself.

The Boric Acid Corrosion Prevention Program is used to manage the aging of carbon steel and LAS SCs and electrical components onto which borated water may leak. The staff evaluation and acceptance of this program can be found in SER Section 3.0.3.2.1. Using provisions in the Boric Acid Corrosion Prevention Program for inspecting, detecting, or monitoring degradation of SCs exposed to boric acid leakage to manage the loss of material in SCs that may be potentially exposed externally to leaking borated water is consistent with GALL Report line items for these listed components. Therefore, this approach is acceptable to the staff. Hence, the staff finds that the applicant's AMR evaluation is consistent with the GALL Report, and the applicant has demonstrated that it will adequately manage the effects of aging 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).

Cracking in Nickel-Based Alloy Weld in Surge, Spray, Relief, and Safety Nozzles and Surge and Spray Nozzle Thermal Sleeves Under Borated Water Environment

Summary of Technical Information in the Application

The applicant identified that PWSCC cracking is an AERM for nickel-based alloy welds in surge, spray, relief, and safety nozzles and surge and spray nozzle thermal sleeves that are exposed to a borated water environment, as indicated in LRA Table 3.1.2-4.

The applicant credited Water Chemistry Control Program (SER Section 3.0.3.2.15), the Alloy 600 Aging Management Program (SER Section 3.0.3.3.1), and the Inservice Inspection Program (SER Section 3.0.3.1) with the management of PWSCC for surge, spray, relief, and safety nozzles, and the Water Chemistry Control and Alloy 600 Aging Management Programs for surge and spray nozzle thermal sleeves.

Staff Evaluation

The applicant identified PWSCC as an applicable aging effect for nickel-based alloy weld pressurizer components that are exposed to a borated water environment. It characterized the AMRs for managing these components as not consistent with the GALL Report line item for the nozzles, and not consistent with the GALL Report line item, except for the use of a different AMP, for thermal sleeves.

Since nickel-based alloy is used in the weld buttering (Alloy 82/182, 52/152), PWSCC is a concern for welds in pressurizer surge, spray, relief, and safety nozzles. The applicant credited the Water Chemistry Control, Alloy 600 Aging Management, and Inservice Inspection Programs for the management of the PWSCC. In this determination, the applicant referenced GALL line item IV.C2.5-k for pressurizer instrument penetrations with Alloy 600 material and adopted the GALL Report recommended Inservice Inspection and the Water Chemistry Control Programs to manage cracking in pressurizer surge, spray, relief, and safety nozzles under a borated water environment. For this line item, the GALL Report further recommends that the applicant provide a plant-specific AMP or participate in industry programs to determine an appropriate AMP for managing PWSCC of Alloy 182 weld material. The applicant's Alloy 600 Aging Management Program is this plant-specific AMP recommended by the GALL Report, and it incorporates the industry effort in managing PWSCC generically.

Therefore, the staff concludes that using the Water Chemistry Control, Alloy 600 Aging Management, and Inservice Inspection Programs to manage cracking in surge, spray, relief, and safety nozzles, is consistent with the GALL Report recommendations for these components and is acceptable.

The applicant credited the Water Chemistry Control and Alloy 600 Aging Management Programs with the management of PWSCC in surge and spray nozzle thermal sleeves. Like pressurizer nozzles discussed above, the applicant referenced GALL line item IV.C2.5-k for pressurizer instrument penetrations with Alloy 600 material for surge and spray nozzle thermal sleeves. However, instead of using the three AMPs recommended by the GALL Report for line item IV.C2.5-k, the applicant adopted only the Water Chemistry Control and Alloy 600 Aging Management Programs to manage cracking in pressurizer surge and spray nozzle thermal sleeves under a borated water environment. Not using the Inservice Inspection Program recommended for GALL line item IV.C2.5-k for thermal sleeves is acceptable because the surge and spray nozzle thermal sleeves, which are mechanically connected to or welded to the safe end of the nozzles, are inaccessible from outside of the nozzles for inspections. Further, the ASME Code does not have inspection requirements for the pressurizer surge and spray nozzle thermal sleeves. Therefore, the staff concludes that using only the Water Chemistry Control and Alloy 600 Aging Management Programs to manage cracking in surge and spray nozzle thermal sleeves is acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cracking in nickel-based alloy weld in surge, spray, relief, and safety nozzles and surge and spray nozzle thermal sleeves under a borated water environment , as recommended in the GALL Report. Since the applicant's AMR results are either consistent with the GALL Report requirements or consistent with the GALL Reports requirements with an acceptable exception, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Pressurizer Summary of Aging Management

The staff reviewed LRA Table 3.1.2-4, which summarized the results of AMR evaluations in the SRP-LR for the pressurizer component groups.

In the LRA, the applicant stated that it will manage the loss of material for LAS clad with stainless steel in treated, borated water using only the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1). Section 3.0.3.2.15 of this SER documents the staff's evaluation of this program. This program applies to the lower head, shell, upper head, surge, spray, relief, and safety nozzles (with nickel-alloy weld buttering), as well as the manway forging.

Industry experience has shown that the effects of general and crevice corrosion, as well as pitting, on cladding made of stainless steel in chemically treated, borated water are not significant. On this basis, the staff finds that the management of this aging effect using water chemistry control is sufficient.

In the LRA, the applicant stated that it will manage the loss of material from stainless steel components in treated, borated water using only the Water Chemistry Control Program. This program includes the following:

- surge, spray, relief, and safety nozzle safe ends
- surge and spray nozzle thermal sleeves
- heater well nozzles and couplings
- immersion heater sheaths
- heater support plates, plate brackets, and plate bracket bolts
- spray head locking bar and couplings
- instrument nozzles and couplings, as well as the manway insert.

The loss of material from the CASS spray head in this environment is managed in the same way.

On the basis of industry experience that the effects of general and crevice corrosion, as well as pitting, on components made of stainless steel (including CASS) in chemically treated, borated water are not significant, the staff finds that the management of this aging effect using water chemistry control is sufficient.

In the LRA, the applicant stated that it will manage the cracking of the heater support plates, their brackets, and the bracket bolts using the Water Chemistry Control Program. Although the applicant cited a precedent, the staff was unable to confirm its applicability. For the component referenced, the GALL Report recommends the use of the Inservice Inspection Program, in addition to the Water Chemistry Control Program.

The staff asked the applicant to justify the absence of an inspection or monitoring program to manage cracking of these components, or to identify the program it uses to accomplish this task. By letter dated August 20, 2004, the staff asked, in RAI 3.1.3-2, that the applicant explain the rationale for excluding the cracking of heater support plates, their brackets, and the bracket bolts from the scope of an inspection or monitoring program, or to identify the program it uses to supplement water chemistry control.

In a letter dated September 2, 2004, in its response to RAI 3.1.3-2, the applicant stated that it credited the Water Chemistry Control and Inservice Inspection Programs to manage cracking of the pressurizer heater sheaths and sleeves, which are the pressure boundary components that are comparable to those in the GALL Report, Volume 2. The pressurizer heater support plates, brackets, and bracket bolts are internal to the pressurizer; they provide lateral support for the heaters and do not have a pressure boundary function.

On the basis of its review of the applicant's response to RAI 3.1.3-2, the staff finds that the applicant will adequately manage the cracking of heater support plates, their brackets, and the bracket bolts using only the Water Chemistry Control Program because these components do not have a pressure boundary intended function and only require management using a mitigative program, such as water chemistry control. On the basis of its review, the staff concludes that there is reasonable assurance that the applicant will manage this aging effect adequately during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it manages the cracking of LAS and carbon steel components exposed to ambient air using the Inservice Inspection Program for the support skirt and flange, seismic lugs, and valve support bracket lugs. The staff found this to be consistent with the GALL Report and therefore acceptable.

In the LRA, the applicant stated that it manages cracking of the LAS manway cover bolts/studs in ambient air using the Inservice Inspection Program. Although the applicant cited a precedent, the staff was unable to determine its applicability. For the component referenced, the GALL Report recommends the use of a program consistent with the Bolting Integrity Program (i.e., GALL AMP XI.M18).

The staff asked the applicant to explain its rationale for excluding this bolting material from the scope of the Bolting and Torquing Activities Program (CNP AMP B.1.2) or to confirm that it is managed using this program. By letter dated August 20, 2004, the staff asked, in RAI 3.1.3-1, that the applicant explain its rationale for excluding LAS manway cover bolts/studs in ambient air from the scope of CNP AMP B.1.2 or confirm that it is managed using this program.

In a letter dated September 2, 2004, in response to RAI 3.1.3-1, the applicant stated that it credited the Bolting and Torquing Activities Program for managing loss of mechanical closure integrity for LAS manway cover bolts/studs in ambient air in LRA Table 3.1.2-4. The applicant also stated that the aging effect of cracking is listed separately for these same components and is managed by the Inservice Inspection Program, which is more appropriate for closure bolting in Class I systems.

On the basis of its review of the applicant's response to RAI 3.1.3-1, the staff finds that the applicant will adequately manage all aging effects on bolting material for LAS manway cover bolts/studs in ambient air using the Inservice Inspection and Bolting and Torquing Activities Programs. The staff further concludes that there is reasonable assurance that the applicant will adequately manage these aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion

On the basis of its audit and review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the pressurizer components so that the component intended functions can 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.1.2.3.5 Steam Generators

Summary of Technical Information in the Application

In LRA Section 3.1.2.1.5 and Table 3.1.2-5, the applicant stated that the steam generator components are fabricated from carbon steel, LAS, LAS clad with stainless steel, LAS clad with nickel-based alloy, stainless steel, and nickel-based alloy. The nickel-based alloys are thermally treated Alloy 690 tubing and Alloy 52/152 weld metal. In Section 3.1.2.1.5 and Table 3.1.2-5 of the LRA, the applicant stated that the components are exposed to treated, borated water, treated water (secondary side), and external-ambient environments. The treated, borated water and treated water environments include steam. The external environment has the potential for limited periods of leaking borated water and steam. Table 3.0-1 of the LRA defines these environments.

In Table 3.1.2-5 of the LRA, the applicant identified the aging effects listed below for the steam generator components requiring AMPs specified in the GALL Report:

- cracking of the following component types exposed to borated water (primary side)—primary head, primary nozzles, primary nozzle safe ends, partition plates and nozzle dam retention rings, primary manway insert plates, tubes and tube plugs, and tubesheet
- cracking of the following component types exposed to the containment ambient atmosphere with periodically leaking boric acid and steam—primary manway closure bolting and secondary manway, handhole, recirculation (Unit 1), and inspection port closure bolting
- cracking of the following component types exposed to treated water (secondary side)—tubes and tube plugs; lower shell, upper shell, transition cone, steam drum, and elliptical upper head; feedwater nozzles; feedwater nozzle thermal sleeve (Unit 1); main steam nozzles; feedwater safe ends (Unit 1); secondary blowdown and instrumentation connections, recirculation connections (Unit 1), and secondary shell drain connections (Unit 2); secondary handhole ports and inspection ports; secondary manways; steam flow restrictors (Unit 1); feedwater elbow thermal liners (Unit 2) and feedwater liner piston rings (Unit 2); tube wrappers (shroud); tube support plates and antivibration bars (AVBs) (Unit 2); tube support plate stayrod nuts (Unit 2); tube support plate stayrod washers and AVB retaining rings (Unit 2); lattice grid ring studs (Unit 1); and lattice grid bars, U-bend flat bars, and J-tabs (Unit 1)
- loss of material of the following components exposed to borated water—primary head, primary nozzles, primary nozzle safe ends, partition plates and nozzle dam retention rings, primary manway insert plate, tubes and tube plugs, and tubesheet cladding
- loss of material of the following components exposed to the containment ambient atmosphere with periodically leaking boric acid and steam—primary head; primary nozzles; primary manway cover; primary manway closure bolting; tubesheet; lower shell, upper shell, transition cone, steam drum, and elliptical upper head; feedwater nozzles; main steam nozzles; secondary blowdown and instrumentation connections, recirculation connections (Unit 1), and secondary shell drain connections (Unit 2); secondary handhole ports and inspection ports; secondary handhole port covers, inspection port covers, and recirculation port covers (Unit 1); secondary manways; secondary manway covers; and secondary manway, handhole, recirculation (Unit 1), and inspection port closure bolting

- loss of material of the following components exposed to treated water (secondary side)—tubes and tube plugs; tubesheet; lower shell, upper shell, transition cone, steam drum, and elliptical upper head; feedwater nozzles; feedwater nozzle thermal sleeve (Unit 1); main steam nozzles; feedwater safe ends (Unit 1); secondary blowdown and instrumentation connections, recirculation connections (Unit 1), and secondary shell drain connections (Unit 2); secondary handhole ports and inspection ports; secondary handhole port covers, inspection port covers, and recirculation port covers (Unit 1); secondary manways; secondary manway covers; steam flow restrictors (Unit 1); feedwater elbow thermal liners (Unit 2) and feedwater liner piston rings (Unit 2); tube wrappers (shroud); tube support plates and AVBs (Unit 2); tube support plate stayrods and tube support plate spacers (Unit 2); tube support plate stayrod nuts (Unit 2); tube support plate stayrod washers and AVB retaining rings (Unit 2); lattice grid ring and U-bend arch bars (Unit 1); lattice grid ring studs (Unit 1); and lattice grid bars, U-bend flat bars, and J-tabs (Unit 1)

- loss of mechanical closure integrity for the following components exposed to the containment ambient atmosphere with periodically leaking boric acid and steam—primary manway closure bolting and secondary manway, handhole recirculation (Unit 1), and inspection port closure bolting

- loss of mechanical closure integrity for the following components exposed to treated water (secondary side)—tube support stay rod nuts (Unit 2) and lattice grid ring studs

In Table 3.1.2-5 of the LRA, the applicant identified the AMPs listed below for managing the aging effects applicable to the steam generator components during the period of extended operation. The following program summaries are based on the information provided in Appendix B to the LRA:

- Alloy 600 Aging Management Program
- Bolting and Torquing Activities Program
- Boric Acid Corrosion Prevention Program
- Flow-Accelerated Corrosion Program
- Inservice Inspection—ASME Section XI, Subsection IWB, IWC, IWD Program
- Steam Generator Integrity Program
- Water Chemistry Control—Primary and Secondary Water Program

<u>Staff Evaluation</u>

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section 3.1, Table 3.1.2-5, and Appendix B to determine if the applicant will adequately manage the effects of aging so that the intended functions of the steam generator components will be maintained consistent with the CLB throughout the period of extended operation. The staff also reviewed the applicable UFSAR Supplements to ensure that the AMPs are adequately described.

Aging Effects

The staff reviewed and evaluated the applicability of the aging effects listed in LRA Table 3.1.2-5 for the steam generator components within the scope of license renewal.

In LRA Section 3.1.2.2.1, "Cumulative Fatigue Damage," the applicant described the TLAAs it performed on components in the RCS pressure boundary. Section 4.7.5, "Steam Generator Tubes—Flow-Induced Vibration," of the LRA addresses the TLAA for fatigue of the steam generator tube bundles. In that section, the applicant stated that the analyses it performed on the tube bundles in Units 1 and 2 steam generators meet the 10 CFR 54.3 definition of a TLAA, and that the analyses remain valid through the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Review of Aging Effects on Steam Generator Items in LRA Table 3.1.1

In Table 3.1.1 of the LRA, the applicant described its proposed management of aging in steam generator components, including any further evaluation recommended in the SRP-LR. Table 3.1.1 of both the LRA and the SRP-LR summarize the following steam generator aging issues, which are evaluated in Chapter IV of the GALL Report.

- pitting and crevice corrosion of the steam generator shell assembly (Item 3.1.1-2)
- erosion of feedwater impingement plate and support (Item 3.1.1-17)
- cracking and loss of material of tubes, repair sleeves, and plugs (Item 3.1.1-18)
- FAC of carbon steel tube support lattice bars (Item 3.1.1-19)
- ligament cracking of carbon steel tube support plates (Item 3.1.1-20)
- FAC of feedwater inlet ring and supports (Item 3.1.1-21)
- FAC of various steam generator components (Item 3.1.1-25)
- loss of material, cracking, and loss of preload of closure bolting (Item 3.1.1-26)
- boric acid corrosion of carbon steel RCPB external surfaces (Item 3.1.1-38)
- erosion of secondary manways and handholds (Item 3.1.1-39)
- SCC of upper and lower heads, tubesheets, primary nozzles, and safe ends (Item 3.1.1-44)

The applicant stated that Items 3.1.1-17, 3.1.1-19, and 3.1.1-20 are not applicable because CNP steam generators do not have feedwater impingement plates, carbon steel lattice bars, or carbon steel tube support plates. The stainless steel tube support lattice bars in Unit 1 and stainless steel tube support plates in Unit 2 are not susceptible to these aging mechanisms. The applicant stated that Item 3.1.1-39, erosion of carbon steel manways and handholds, is not applicable to the CNP recirculating steam generators because it applies only to once-through steam generators. The staff agrees that these four items are not applicable to CNP.

RAI 3.1-1

With regard to Item 3.1.1-2, the applicant's plan is consistent with the GALL AMP for managing pitting and crevice corrosion of the shell assembly; however, the applicant did not discuss the augmented inspection recommended by the GALL Report. By letter dated May 19, 2004, the staff requested, in RAI 3.1-1, that the applicant describe the details of the augmented inspection for the shell assembly and explain this inspection's management of the aging effect (Item 3.1.1-2 in Table 3.1.1). The aging effect is loss of material due to pitting and crevice corrosion, which may not be detected by the Inservice Inspection and Water Chemistry Control Programs. Section 3.1.2.2.2 of the SRP-LR recommends an augmented inspection for this aging effect. The applicant stated that it will supplement the Water Chemistry Control Program with the Steam Generator Integrity Program for secondary-side components. However, the

Steam Generator Integrity Program description, NEI 97-06, or the EPRI Steam Generator Examination Guidelines do not include such an inspection.

In a letter dated August 11, 2004, the applicant responded that an augmented inspection is necessary only if this aging effect is known to exist, and that the internal surfaces of the steam generator shells at CNP have not experienced pitting corrosion. The applicant stated that augmented inspections of the upper shell-to-transition cone girth welds would be added to the Inservice Inspection Program as part of the assessment of degradation mechanisms and industry operating events performed under the Steam Generator Integrity Program. Because the steam generator shells at CNP have not experienced pitting or crevice corrosion, and augmented inspections will be added if the industry experiences pitting or crevice corrosion in this area, the staff accepts the Water Chemistry Control and Steam Generator Integrity Programs for managing aging of the shell assembly.

In Item 3.1.1-18, the applicant addressed the aging effects of cracking, loss of material, and deformation of steam generator tubes, plugs, and sleeves. The aging effects include (1) crack initiation and growth due to PWSCC, ODSCC, or IGA, (2) loss of material due to wastage and pitting corrosion, (3) loss of material due to fretting or wear, and (4) deformation due to corrosion at tube support plate intersections. Section 3.0.3 of this SER presents the staff's evaluation of the aging management plan for these components. The staff concluded that the applicant adequately evaluated these aging issues according to the GALL Report recommendations. Therefore, the staff's concern described in RAI 3.1-1 is resolved

RAI 3.1-2

Item 3.1.1-21 addresses FAC of the steam generator feedwater inlet ring and supports. The applicant omitted these components from the scope of license renewal on the basis that the aging effect applies only to CE System 80 steam generators. However, the staff was aware that J-nozzles at one plant had to be replaced in 1989 due to erosion-corrosion, and a leak occurred at another plant at a previously plugged bottom spray hole in 1995. Therefore, in a letter dated May 19, 2004, the staff requested, in RAI 3.1-2, that the applicant explain how it will manage the aging of the feedwater ring assembly, including the J-nozzles. In a letter dated August 11, 2004, the applicant responded that these aging concerns do not apply because the CNP steam generators have Alloy 690 J-tubes and do not have plugged bottom spray holes. The staff accepts this justification, but the details will not be discussed here. In a separate letter dated May 20, 2004, responding to RAI 2.3.1.6-2 from the NRC Reactor Systems Branch (SRXB), the applicant stated that the feedwater ring and J-tubes are not within the scope of license renewal because they do not directly support the steam generator pressure boundary function, they are not required for mitigation or recovery from any DBEs or regulated events at CNP, and systems of this design have experienced no failures. As discussed in Section 2.3.1.5 of this SER, SRXB has concluded that the components are not within scope for the application. The staff's concern described in RAI 3.1-2 is resolved.

Item 3.1.1-25 addresses FAC of various steam generator components, such as main steam nozzles and Unit 2 feedwater elbow thermal liners. As recommended in the GALL Report, the applicant manages aging of these components using the Flow-Accelerated Corrosion Program, which is consistent with the program in the GALL Report. The applicant will supplement this program with the Water Chemistry Control Program, which, with enhancements, will also be consistent with the GALL Report for primary and secondary water chemistry. Feedwater nozzles are protected by nickel-based thermal sleeves (Unit 2) and carbon steel thermal liners (Unit 1), which are evaluated in Table 3.1.2-5 and discussed below.

Item 3.1.1-26 addresses the loss of material (wear), the loss of preload (stress relaxation), and crack initiation and growth (cyclic loading and/or SCC) in closure bolting for the RCPB, including primary- and secondary-side steam generator closures. The SRP-LR and GALL Report list the Bolting Integrity Program as the appropriate AMP for this aging issue. The applicant plans to use ISI to manage loss of material and cracking for these components. The applicant will manage the loss of mechanical closure integrity using the Bolting and Torquing Activities, Inservice Inspection, and Boric Acid Corrosion Prevention Programs for steam generator closures. The staff finds this combination of AMPs acceptable because they include the same activities as the GALL program for which they substitute (i.e., Bolting Integrity Program). The Bolting Integrity Program refers to ISI, inspection for leakage and corrosion, and selection and installation of bolting material. Like the GALL report Bolting Integrity Program, the applicant's Bolting and Torquing Activities Program relies on EPRI recommendations. The GALL Report does not address corrosion and cracking of steam generator bolting in the external-ambient environment (listed in LRA Table 3.1.2-5); however, Section 3.0.3.3.2 of this SER does discuss this environment.

Item 3.1.1-44 addresses crack initiation and growth due to SCC, PWSCC, and IASCC of steam generator upper and lower heads, tubesheets, primary nozzles, and safe ends. Except for the tubesheet, the applicant manages these aging effects with the Alloy 600 Aging Management, Inservice Inspection, and Water Chemistry Control Programs. These programs are consistent with Chapter IV of the GALL Report, except for the Alloy 600 Aging Management Program which is a new, plant-specific program that the applicant will implement before the period of extended operation. However, the applicant will base this program on ASME Code Section XI and will submit it to the staff for review and approval 2–3 years before the period of extended operation. The staff therefore accepts the applicant's conclusion that this aging management approach is consistent with the GALL Report and will effectively manage SCC, PWSCC, and IASCC in these components. Table 3.1.2-5 addresses aging management for the tubesheet, which is not listed in Chapter IV of the GALL Report. This issue is also discussed below.

Review of Aging Effects on Steam Generator Items in LRA Table 3.1.2-5

In LRA Table 3.1.2-5, the applicant indicated the steam generator aging effects that are identified for aging management as a result of the applicant's license renewal review, but are not addressed by the GALL Report. For some items, the staff requested additional information from the applicant to perform a thorough evaluation. Those items are discussed below.

According to LRA Table 3.1.2-5, the applicant credited the Water Chemistry Control Program (along with the Steam Generator Integrity Program in some cases) for managing the loss of material and cracking during the extended operating period. This applies to the following components managed for the loss of material:

- stainless steel cladding on the primary head in borated water
- stainless steel cladding on the primary nozzles in borated water
- stainless steel primary nozzle safe ends in borated water
- nickel-based alloy partition plates and nozzle dam retention rings in borated water
- nickel-based alloy and stainless steel primary manway insert plates in borated water

- nickel-based alloy tubes and plugs in borated water and in treated water
- nickel-based alloy tubesheet cladding in borated water
- LAS tubesheet in treated water
- LAS feedwater nozzles in treated water
- nickel-based alloy feedwater nozzle thermal sleeve (Unit 1) in treated water
- nickel-based alloy feedwater safe ends (Unit 1) in treated water
- LAS blowdown, instrument, and other connections in treated water
- LAS handhole, inspection, and recirculation port covers in treated water
- stainless steel steam flow restrictors (Unit 1) in treated water
- nickel-based alloy feedwater liner piston rings (Unit 2) in treated water
- carbon steel tube wrappers (shroud) in treated water
- stainless steel tube support plates and antivibration bars (Unit 2) in treated water
- carbon steel tube support plate stayrods, spacers (Unit 2), and stayrod nuts in treated water
- nickel-based alloy tube support plate stayrod washers and AVB retaining rings (Unit 2) in treated water
- carbon steel lattice grid rings, lattice grid ring studs (Unit 1), and U-bend arch bars (Unit 1) in treated water
- stainless steel lattice grid bars, U-bend flat bars, and J-tabs (Unit 1) in treated water

It also applies to the following components managed for cracking:

- carbon steel tube wrappers (shroud) in treated water
- stainless steel tube support plates and antivibration bars (Unit 2) in treated water
- carbon steel tube support plate stayrod nuts (Unit 2) in treated water
- nickel-based alloy tube support plate stayrod washers and AVB retaining rings (Unit 2) in treated water
- carbon steel lattice grid ring studs (Unit 1) in treated water
- stainless steel lattice grid bars, U-bend flat bars, and J-tabs (Unit 1) in treated water

RAIs 3.1-3 and 3.1-4

The staff considered the applicant's discussion incomplete for the components listed above because water chemistry control is a preventive strategy, and the Steam Generator Integrity Program does not specify how to detect these aging effects. Therefore, by letter dated May 19, 2004, the staff requested, in RAIs 3.1-3 and 3.1-4, that the applicant identify the aging mechanisms for these components and describe how it would detect and monitor the loss of material or cracking, if prevention fails. (Section 3.0.3.1 of this SER evaluates the Steam Generator Integrity Program.)

In a letter dated August 11, 2004, the applicant responded that it would maintain the water chemistry according to the EPRI Primary Water Chemistry Guidelines to manage general, pitting, and crevice corrosion of stainless steel and nickel-based components exposed to borated (primary) water. These guidelines limit oxygen to less than 100 parts per billion (ppb), and chloride, fluoride, and sulfate concentrations to less than 150 ppb each. The staff has reviewed these guidelines and confirmed the limits, as well as the fact that stainless steel and the relevant nickel-based alloys resist corrosion in this environment. The staff finds the applicant's primary water chemistry control approach acceptable for managing general, pitting, and crevice corrosion of these stainless steel and nickel-based primary-side components.

To prevent crevice corrosion and cracking of carbon steel, LAS, stainless steel, and nickel-based steam generator internals exposed to treated (secondary) water, the applicant stated, in a letter dated August 11, 2004, that it would maintain secondary water chemistry consistent with EPRI Secondary Water Guidelines. In the August 11, 2004, letter, and in a letter dated August 19, 2004, the applicant responded to RAI 3.1-4 (and the related RAI B.1.31-1) by explaining that all secondary-side internals that form the tube support structure are within the scope of secondary-side visual inspection under the Steam Generator Integrity Program. The applicant also stated that these components are representative of components inspected visually as part of the Steam Generator Integrity Program (CNP AMP B.1.31). The applicant stated that it completes a steam generator degradation assessment before these inspections to focus the inspections adequately on the expected degradation mechanisms. Based on this assessment, the applicant performs visual examinations of the secondary-side internal components included in LRA Table 3.1.2-5 to detect degraded conditions. If degraded conditions are found, the applicant documents the condition through the Corrective Action Program and expands the inspection scope in the area of interest until the condition is bounded. The applicant identified the major focus areas as the tubesheet region, tube support structures, U-bend region, and feedwater distribution system.

In a public meeting on September 1, 2004, documented as a follow-up to RAI 3.1-1 in a letter dated September 29, 2004, the staff requested the applicant to explain the frequency of the steam generator secondary-side inspections. By letter dated October 18, 2004, the applicant stated that the interval for secondary side visual inspections is no more than two operating cycles. The scope of the inspections is based on plant-specific degradation assessments that consider operating experience at CNP and with other steam generators of similar design. The staff concludes that this is acceptable because these components are subject to inspection under the Steam Generator Integrity Program. In addition, the frequency of inspection is a maximum of every second outage, degradation assessments are performed prior to the inspection to focus inspections on susceptible locations, and no degradation problems have occurred to date with the replacement steam generators. The staff therefore concludes that both the Water Chemistry Control and Steam Generator Integrity Programs effectively manage cracking of the listed components. Hence, the staff's concerns described in RAIs 3.1-3 and 3.1-4 are resolved.

RAI 3.1-5

According to LRA Table 3.1.2-5, the applicant credited the Water Chemistry Control and Steam Generator Integrity Programs for managing the fouling of tubes. In a letter dated May 19, 2004, the staff requested, in RAI 3.1-5, that the applicant describe how it would detect and monitor the fouling, if prevention fails. In a letter dated August 11, 2004, the applicant responded that fouling of steam generator tubes is the result of corrosion product accumulation on the tube surfaces (primarily the tube exterior surface), which reduces the ability of the tubes to transfer heat. The Water Chemistry Control—Primary and Secondary Water Chemistry Control Program is a mitigation program that maintains an environment in which corrosion products are limited to minimize aging effects. As part of the Steam Generator Integrity Program, the applicant performs sludge lancing to remove bulk materials from the secondary side of the steam generators and visual inspections of the tubes to access deposit buildup. Based upon the inspection findings, the applicant initiates and develops mitigation strategies (e.g., bundle flushing, chemical cleaning) through its Corrective Action Program, as required to ensure continued operation without a performance (heat transfer) penalty. The staff finds that the applicant adequately addressed the possibility of tube fouling because the Steam Generator Integrity Program and, if necessary, the Corrective Action Program includes cleaning of the tubes. Therefore, the staff's concern described in RAI 3.1-5 is resolved.

RAI 3.1-6

Table 3.1.2-5 of the LRA lists both the loss of material and cracking as aging mechanisms for carbon steel closure bolts in the external-ambient environment (page 3.1-90). The staff noted that it is unusual for cracking, especially SCC, to occur in a particular alloy in the same environment that causes substantial general corrosion. Therefore, by letter dated May 19, 2004, the staff requested, in RAI 3.1-6, that the applicant identify the mechanisms and specific environments causing these aging effects.

In a letter dated August 11, 2004, the applicant stated that the bolting associated with the steam generator manways and inspection ports is fabricated from SA-193 Grade B7 material, which is susceptible to SCC and fatigue cracking. Although these fasteners are not intentionally exposed to water or steam, inadvertent exposure may result if leaks occur. If leakage is combined with contaminant species, such as sulfides or chlorides, an aggressive environment that can promote SCC may result. Therefore, cracking of the steam generator bolting is considered an AERM for the period of extended operation. While the external surfaces of the steam generators and bolting are not normally exposed to RCS fluid, the potential for boric acid wastage exists because of leakage from the bolted closure. Therefore, external surfaces of the steam generator closure bolts fabricated from ferritic steel are potentially subject to the loss of material.

The response makes it clear that the bolting is high-strength steel and that the applicant is considering two separate external environments that could potentially be present and could degrade the bolts. Water or steam leaks could create an environment that causes SCC, while leakage of RCS fluid could cause boric acid wastage. The applicant intends to manage boric acid wastage with the Boric Acid Corrosion Prevention Program, as specified in the GALL Report. The staff finds this acceptable for managing boric acid corrosion because the applicant's program is consistent with the GALL Report, which includes inspection of steam generator closure bolting for boric acid corrosion through reference to GL 88-05. The applicant intends to manage SCC, which is not an aging effect identified in the GALL Report for this component, with the Inservice Inspection Program. The staff considers this acceptable because the applicant's Inservice Inspection Program is consistent with GALL AMP XI.M1, which includes inspection for cracking of pressure-retaining steam generator bolting. Therefore, the staff's concern described in RAI 3.1-6 is resolved.

Aging Management Programs

In the LRA, the applicant stated that the primary head and primary nozzles of the steam generator are fabricated from LAS clad with stainless steel. All are exposed to treated, borated water. For these components, the applicant proposed to manage loss of material using only the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1). Section 3.0.3.2.15 of this SER documents the staff's evaluation of this program, which is consistent with the GALL Report and therefore acceptable to the staff.

In the LRA, the applicant stated that the primary nozzle safe end and the primary manway insert plate (Unit 2) are made of stainless steel and are exposed to treated, borated water. For these components, the applicant proposed to manage the loss of material using only the Water Chemistry Control Program. This is consistent with the GALL Report and acceptable to the staff.

In the LRA, the applicant stated that the partition plates, nozzle dam retention rings, primary manway insert plate (Unit 1), and tube plugs are made of nickel-based alloy or LAS clad with nickel-based alloy. The tubesheet (primary side) is LAS clad with nickel-based alloy. All are exposed to treated, borated water. For these components, the applicant proposed to manage the loss of material using only the Water Chemistry Control Program. This is consistent with the GALL Report and acceptable to the staff.

In the LRA, the applicant stated that the feedwater nozzle thermal sleeve, feedwater safe ends (Unit 1) and feedwater liner piston rings (Unit 2) are made of nickel-based alloy. All are exposed to treated water. For these components, the applicant proposed to manage loss of material using only the Water Chemistry Control Program. This is consistent with the GALL Report and therefore acceptable to the staff.

In the LRA, the applicant stated that it manages cracking of the LAS lower shell, upper shell, transition cone, steam drum, elliptical upper head, feedwater nozzle and main steam nozzle, secondary blowdown and instrumentation connections, recirculation connections (Unit 1), secondary shell drain connections, secondary handhole, and inspection ports in treated water using the Inservice Inspection—ASME Section XI, Subsection IWB, IWC, and IWD Program (CNP AMP B.1.14). Section 3.0.3.1 of this SER documents the staff's evaluation of this program.

RAI 3.1.3-4

The applicant made reference to a previously approved staff position, however, the case cited credits a water chemistry control program, as well. The applicant did not identify the Water Chemistry Control Program for managing this aging effect. The staff asked the applicant to provide the basis for concluding that water chemistry control is not required or to identify the water chemistry control program that it will use. By letter dated August 20, 2004, the staff asked, in RAI 3.1.3-4, that the applicant explain the rationale for excluding a water chemistry control program for managing cracking of the above components in treated water, or to identify the water chemistry control program that it will use.

In a letter dated September 2, 2004, in its response to RAI 3.1.3-4, the applicant stated that because the components are fabricated of LAS exposed to a treated water environment, they are susceptible to the loss of material, which is managed by the Water Chemistry Control Program. These components are also susceptible to cracking from metal fatigue, which is a TLAA, and cracking from growth of preservice flaws, which is managed by the Inservice Inspection Program and not mitigated by water chemistry control.

On the basis of its review of the applicant's response to RAI 3.1.3-4, the staff finds that the applicant will adequately manage cracking and the loss of material of LAS components exposed to a treated water environment using both the Inservice Inspection and Water Chemistry Control Programs. On the basis of its review, the staff concludes that the applicant will adequately manage this aging effect during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it will manage cracking of nickel-based alloy in treated water for the feedwater nozzle thermal sleeve, feedwater safe end (Unit 1), and feedwater liner piston rings (Unit 2) using the Water Chemistry Control and Inservice Inspection Programs. The staff finds this to be acceptable.

In the LRA, the applicant stated that it manages the cracking of carbon steel in treated water for the secondary manway and the feedwater elbow thermal liner (Unit 2) using the Inservice Inspection Program. The applicant made reference to a previously approved staff position, however, the case cited credits a water chemistry control program, as well. The applicant did not identify the Water Chemistry Control Program for managing this aging effect.

The staff asked the applicant to provide the basis for concluding that water chemistry control is not required or to identify the water chemistry control program that it will use. By letter dated August 20, 2004, the staff asked, in RAI 3.1.3-4, that the applicant explain its rationale for excluding a water chemistry control program for managing cracking of the above components in treated water, or to identify the water chemistry control program that it will use.

In a letter dated September 2, 2004, in its response to RAI 3.1.3-4, the applicant stated that because the components are fabricated of carbon steel exposed to a treated water environment, they are susceptible to the loss of material, which is managed by the Water Chemistry Control Program. These components are also susceptible to cracking from metal fatigue, which is a TLAA, and cracking from growth of preservice flaws, which is managed by the Inservice Inspection Program and not mitigated by water chemistry control.

On the basis of its review of the applicant's response to RAI 3.1.3-4, the staff finds that the applicant will adequately manage cracking and loss of material of carbon steel components exposed to a treated water environment using both the Inservice Inspection and Water Chemistry Control Programs. Therefore, the staff's concern described in RAI 3.1.3-4 is resolved. On the basis of its review, the staff concludes that the applicant will adequately manage this aging effect during the period of extended operation, as required by 10 CFR 54.21(a)(3).

RAI 3.1.3-1

In the LRA, the applicant stated that it manages the cracking of carbon steel bolting of the secondary manway, handhole, recirculation port (Unit 1), and inspection port closure in ambient air using the Inservice Inspection Program. Although the applicant cited a precedent, the staff was unable to confirm its applicability. For the component referenced, the GALL Report recommends the use of a program consistent with the Bolting Integrity Program (GALL AMP XI.M18).

By letter dated August 20, 2004, the staff asked, in RAI 3.1.3-1, that the applicant explain its rationale for excluding carbon steel bolting of the secondary manway, handhole, recirculation port (Unit 1), and inspection port closure in ambient air from the scope of its Bolting and Torquing Activities Program (CNP AMP B.1.2) or to confirm that it uses this program to manage the aging effect.

In a letter dated September 2, 2004, in response to RAI 3.1.3-1, the applicant stated that it credited the Bolting and Torquing Activities Program for managing the loss of mechanical closure integrity for the carbon steel bolting of the secondary manway, handhole, recirculation port (Unit 1), and inspection port closure in ambient air in LRA Table 3.1.2-5. The applicant also stated that it listed the aging effect of cracking for these same components because it uses the Inservice Inspection Program, which is more appropriate for closure bolting in Class I systems, to manage this aging effect.

On the basis of its review of the applicant's response to RAI 3.1.3-1, the staff finds that the applicant will adequately manage all aging effects of bolting material for carbon steel bolting of the secondary manway, handhole, recirculation port (Unit 1), and inspection port closure in ambient air by use of the Inservice Inspection and Bolting and Torquing Activities Program. Therefore, the staff's concern described in RAI 3.1.3-1 is resolved. On the basis of its review, the staff concludes that the applicant will adequately manage these aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it will manage the loss of material from the stainless steel steam flow restrictors (Unit 1) in treated water using the Water Chemistry Control Program.

In the LRA, the applicant stated that it will manage cracking of the stainless steel steam flow restrictors (Unit 1) in treated water using the Water Chemistry Control and Inservice Inspection Programs. During the audit, the staff asked the applicant how it would perform such an inspection. By letter dated April 23, 2004, the applicant stated that ISI should not be credited for the steam flow restrictors. On the basis of industry and plant-specific operating experience, the staff concludes that the Water Chemistry Control Program will be acceptable for managing cracking of the steam flow limiter.

The staff evaluated all other assigned AMRs in Tables 3.1.2-1 through 3.1.2-5 of the LRA. The staff evaluated those that were not accepted, as reviewed and documented above, and Section 3.0 of this SER discusses those that are related to the CNP LRA.

<u>Conclusion</u>

On the basis of its audit and 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 generator components so that the components intended functions can 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.1.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the reactor vessel, internals, RCS, pressurizer, and steam generator components and component types that are within the scope of license renewal and subject to an AMR 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).

3.2 Aging Management of Engineered Safety Features Systems

This section of the Safety Evaluation Report (SER) documents the staff's review of the applicant's Aging Management Review (AMR) results for the Engineered Safety Features (ESF) systems components and component groups associated with the following systems:

- containment spray system
- containment isolation system
- emergency core cooling system
- containment equalization/hydrogen skimmer system

3.2.1 Summary of Technical Information in the Application

In Section 3.2 of the LRA, the applicant provided the AMR results for the ESF system components and component types listed in LRA Tables 2.3.2-1 through 2.3.2-4. The applicant also listed the materials, environments, AERMs, and AMPs associated with each system.

In Table 3.2.1, "Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of NUREG-1801," of the LRA, the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the ESF system components and component types. In Section 3.2.2.2 of the LRA, the applicant provided information concerning Table 3.2.1 components for which the GALL Report recommends further evaluation.

3.2.2 Staff Evaluation

The staff reviewed Section 3.2 of the LRA to understand the applicant's review process and to determine whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the ESF system components that are within the scope of license renewal and subject to an AMR 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 performed an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. Section 3.2.2.1 of this SER presents the staff's audit and review findings.

The staff also audited and reviewed those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's additional evaluations are consistent with the acceptance criteria in Section 3.2.3.2 of the SRP-LR. Section 3.2.2.2 of this SER summarizes the staff's audit and review findings.

The staff conducted a technical review of the remaining AMRs that are not consistent with the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects and listed appropriate aging effects for the combination of materials and environments specified. Section 3.2.2.3 of this SER documents the staff's review findings.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they adequately describe the programs credited with managing or monitoring aging for the ESF systems components and component groups.

Table 3.2-1 below summarizes 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 of Engineered Safety Feature Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings, and valves in the ECCS (Item Number 3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.1)
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and ECCS (Item Number 3.2.1-3)	Loss of material due to general corrosion	Plant specific	System Walkdown Program (B.1.38)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.2)
Components in containment spray (PWR only), standby gas treatment (BWR only), and ECCS (Item Number 3.2.1-5)	Loss of material due to pitting and crevice corrosion	Plant specific	Water Chemistry Control Program (B.1.40); Wall Thinning Monitoring Program (B.1.39); Containment Leakage Rate Testing Program (B.1.8)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.3)
Containment isolation valves and associated piping (Item Number 3.2.1-6)	Loss of material due to MIC	Plant specific	Water Chemistry Control Program (B.1.40); Wall Thinning Monitoring Program (B.1.39); Containment Leakage Rate Testing Program (B.1.8)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
High-pressure safety injection (charging) pump miniflow orifice (Item Number 3.2.1-8)	Local loss of material due to erosion	Plant specific	System Testing Program (B.1.37)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.6)
External surface of carbon steel components (Item Number 3.2.1-10)	Loss of material due to general corrosion	Plant specific	System Walkdown Program (B.1.38)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.2)
Piping and fittings of CASS in the ECCS (Item Number 3.2.1-11)	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Components serviced by open-cycle cooling system (Item Number 3.2.1-12)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-cycle cooling water system	Service Water System Reliability Program (B.1.29); Heat Exchanger Monitoring Program (B.1.13)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Components serviced by closed-cycle cooling system (Item Number 3.2.1-13)	Loss of material due to general, pitting, and crevice corrosion	Closed-cycle cooling water system	Water Chemistry Control—Closed Cooling Water Chemistry Control Program (B.1.40.2); Heat Exchanger Monitoring Program (B.1.13)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Pumps, valves, piping, and fittings, and tanks in containment spray and ECCS (Item Number 3.2.1-15)	Crack initiation and growth due to SCC	Water chemistry	Water Chemistry Control Program (B.1.40)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Carbon steel components (Item Number 3.2.1-17)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Closure bolting in high-pressure or high-temperature systems (Item Number 3.2.1-18)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	Bolting and Torquing Activities Program (B.1.2); Boric Acid Corrosion Prevention Program (B.1.4); System Walkdown Program (B.1.38)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)

The staff's review of the ESF system components and associated components followed one of several approaches. One approach, documented in Section 3.2.2.1 of this SER, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.2.2.2 of this SER, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.2.2.3 of this SER, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. Section 3.0.3 of this SER presents the staff's review of AMPs that are credited with managing or monitoring aging effects of the ESF systems components and associated components.

3.2.2.1 Aging Management Evaluations That Are Consistent with the GALL Report, for Which No Further Evaluation Is Required

Summary of Technical Information in the Application

In Section 3.2.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the ESF system components:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- Inservice Inspection—ASME Section XI, Augmented Inspections Program
- Service Water System Reliability Program
- System Walkdown Program
- Water Chemistry Program
- Bolting and Torquing Activities Program
- Containment Leakage Rate Testing Program
- Wall Thinning Monitoring Program
- Oil Analysis Program
- Preventive Maintenance Program
- System Testing Program

Staff Evaluation

In Tables 3.2.2-1 through 3.2.2-4 of the LRA, the applicant summarized the AMRs for the ESF systems and identified which AMRs it considered to be consistent with the GALL Report.

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 does not recommend further evaluation, the staff performed an audit and review to determine whether the GALL Report evaluation bounds the plant-specific components contained in these GALL Report component groups.

The applicant provided a note for each AMR line item. The notes describe the alignment of the information in the tables with the information in the GALL Report. The staff audited those AMRs with notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant could not find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component is applicable to the component under review. The staff verified whether the staff had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA and program basis documents, which are available at the applicant's engineering office. On the basis of its audit and review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant identified the applicable aging effects which are appropriate for the combination of materials and environments listed.

On the basis of its audit and review, the staff concludes that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Conclusion

The staff has verified the applicant's claim of consistency with the GALL Report. The staff has also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are in fact consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for these components so that their intended functions 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 That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application

In Section 3.2.2.2 of the LRA, the applicant provided further evaluation of aging management as recommended by the GALL Report for ESF systems. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general corrosion
- local loss of material due to pitting and crevice corrosion
- local loss of material due to microbiologically influenced corrosion
- changes in properties due to elastomer degradation
- local loss of material due to erosion
- buildup of deposits due to corrosion

Staff 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 had adequately addressed the issues that received additional evaluation. In addition, the staff audited the applicant's further evaluations against the criteria contained in Section 3.2.2.2 of the SRP-LR. The staff's audit and review report presents details of this effort.

The GALL Report indicates that the aging effects described in the following sections should receive further evaluation.

3.2.2.2.1 Cumulative Fatigue Damage

As stated in the SRP-LR, fatigue is a TLAA as defined in 10 CFR 54.3. The TLAAs must be evaluated in accordance with 10 CFR 54.21(c)(1). Section 4.3 of this SER documents the staff's review of the applicant's evaluation of this TLAA. In performing this review, the staff followed the guidance in Section 4.3 of the SRP-LR.

3.2.2.2.2 Loss of Material due to General Corrosion

In LRA Section 3.2.2.2.2, the applicant addressed the loss of material due to general corrosion that could occur in the containment spray, containment isolation valves and associated piping, and the external surfaces of carbon steel components.

Section 3.2.2.2.2 of the SRP-LR states that the loss of material due to general corrosion could occur in the containment spray, containment isolation valves and associated piping, and the external surfaces of carbon steel components. The GALL Report recommends further evaluation on a plant-specific basis to ensure adequate management of the aging effect.

The applicant stated in the LRA that it credits the plant-specific CNP AMP B.1.38, "System Walkdown," with managing the aging effect of loss of material due to general corrosion on external surfaces of carbon steel components in the containment penetrations system. The applicant also stated that the containment spray system and the ECCS have no carbon steel components. In LRA Table 3.2.1, Item 3.2.1-10, the applicant also stated that the System Walkdown Program manages the loss of material due to general corrosion on external surfaces of carbon steel components. The staff evaluation of this program appears in Section 3.0.3.3.14 of this SER.

On the basis of its review of the System Walkdown Program, the staff finds that the applicant has appropriately evaluated AMR results involving management of the loss of material due to general corrosion, as recommended in the GALL Report.

3.2.2.2.3 Local Loss of Material due to Pitting and Crevice Corrosion

In LRA Section 3.2.2.2.3, the applicant addressed the local loss of material from pitting and crevice corrosion that could occur in the containment spray components, containment isolation valves and associated piping, and ECCS.

Section 3.2.2.2.3 of the SRP-LR states that the local loss of material from pitting and crevice corrosion could occur in the containment spray components, containment isolation valves and associated piping, and ECCS. The GALL Report recommends further evaluation to ensure adequate management of the aging effect.

In the LRA, the applicant credited the Water Chemistry Control—Primary and Secondary Water Chemistry Control (CNP AMP B.1.40.1), the Wall Thinning Monitoring (CNP AMP B.1.39), and the Containment Leakage Rate Testing (CNP AMP B.1.8) Programs with managing the aging effect of the loss of material due to pitting and crevice corrosion. The staff's evaluation of these AMPs appears in Sections 3.0.3.2.15, 3.0.3.3.15, and 3.0.3.1 of this report, respectively.

Section 3.2.2.2.3.2 of the SRP-LR requires verification of the programs' effectiveness and identifies one-time inspections as an acceptable verification method. The Wall Thinning Monitoring Program includes periodic (rather than one-time) inspection of appropriately selected sample components. This approach is acceptable to the staff.

On the basis of its review of the Water Chemistry Control, Wall Thinning Monitoring, and Containment Leakage Rate Testing Programs, the staff finds that the applicant has appropriately evaluated AMR results involving management of the loss of material due to pitting and crevice corrosion, as recommended in the GALL Report.

3.2.2.2.4 Local Loss of Material due to Microbiologically Influenced Corrosion

In LRA Section 3.2.2.2.4, the applicant addressed the local loss of material due to Microbiologically Influenced Corrosion (MIC).

Section 3.2.2.2.4 of the SRP-LR states that the local loss of material due to MIC could occur in 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 adequate management of the aging effect.

The applicant in the LRA credited the Water Chemistry Control—Primary and Secondary Water Chemistry Control (CNP AMP B.1.40.1), Wall Thinning Monitoring (CNP AMP B.1.39), and Containment Leakage Rate Testing (CNP AMP B.1.8) Programs with managing the aging effect of the loss of material due to MIC. The staff evaluation of these programs appears in Sections 3.0.3.2.15, 3.0.3.3.15, and 3.0.3.1 of this report, respectively.

On the basis of its review of the Water Chemistry Control, Wall Thinning Monitoring, and Containment Leakage Rate Testing Programs, the staff finds that the applicant has appropriately evaluated AMR results involving management of the loss of material due to MIC, as recommended in the GALL Report.

3.2.2.2.5 Changes in Properties due to Elastomer Degradation

The applicant stated that this issue applies to BWRs only; therefore, it is not applicable to CNP. The staff concurs.

3.2.2.2.6 Local Loss of Material due to Erosion

In LRA Section 3.2.2.2.6, the applicant addressed the local loss of material due to erosion that could occur in the high-pressure safety injection (HPSI) miniflow orifice.

Section 3.2.2.2.6 of the SRP-LR states that the local loss of material due to erosion could occur in the HPSI pump miniflow orifice. This aging mechanism and its effect will apply only to pumps that are normally used as charging pumps in the chemical and volume control systems. The GALL Report recommends further evaluation to ensure adequate management of the aging effect.

The applicant stated in the LRA that it uses the chemical and volume control charging pumps and not the HPSI pumps for RCS makeup at CNP. The applicant credited the System Testing Program (CNP AMP B.1.37) with managing this aging effect for the charging pump miniflow orifice. The staff's evaluation of this program appears in Section 3.0.3.3.13.

On the basis of its review of the system testing program, the staff finds that the applicant has appropriately evaluated AMR results involving management of the loss of material due to erosion, as recommended in the GALL Report.

3.2.2.2.7 Buildup of Deposits due to Corrosion

The applicant stated that this issue applies to BWRs only; therefore, it is not applicable to CNP. The staff concurs.

3.2.2.2.8 Quality Assurance and Management of Nonsafety related Components

Section 3.0.4 of this SER provides the staff's evaluation of the applicant's Quality Assurance Program.

<u>Conclusion</u>

On the basis of its review, 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 determines that the applicant has adequately addressed the issues that have received further evaluation. In addition, the staff reviewed the applicant's additional evaluations against the criteria contained in the SRP-LR. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

3.2.2.3 AMR Results That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report

<u>Staff Evaluation</u>

The technical staff reviewed the AMR of the ESF component, material, environment, and AERM combinations that are not addressed in the GALL Report and specific combinations addressed in the GALL Report that are within the scope of review. The AERM combinations not addressed in the GALL Report use notes F through J in LRA Tables 3.2.2-1 through 3.2.2-4. The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for the component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that neither the identified component nor the material and environment combination is evaluated in the GALL Report.

Aging Effects

Tables 3.2.2-1 through 3.2.2-4 of the LRA list individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR include bolting, tanks, thermowells, valves, and heat exchangers.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel components subject to an external air environment are subject to the aging effects of loss of material and loss of mechanical closure integrity.
- Stainless steel components exposed to a raw and treated water environment are subject to loss of material—wear.
- Stainless steel components exposed to a sodium hydroxide environment are subject to cracking and loss of material.
- Stainless steel components exposed to treated and untreated borated water environments are subject to the aging effects of cracking-fatigue and loss of material.
- Copper alloys exposed to external air and treated water environments are subject to the aging effects of fouling and loss of material.

The staff reviewed the information in Sections 2.3.2.1 through 2.3.2.4 and Tables 3.2.2-1 through 3.2.2-4 in the LRA. During its review, the staff determined that it needed additional information to complete its evaluation.

By letter dated May 26, 2004, the staff requested that the applicant provide additional information on the issues described in the system-specific RAIs. By letter dated June 30, 2004, the applicant responded to the RAIs. The following describes the responses to these RAIs and the staff's evaluation of the responses. This section presents those RAIs and evaluations of the applicant's responses that apply to several or all subsystems of the ESF system. Sections 3.3.2.3.2 through 3.3.2.3.5 of this SER present the RAIs specific to the subsystems and the evaluation of the applicant's responses.

RAI 3.2-1

Table 3.2.1 and Section 3.2.2.2.1 of the LRA identify the applicant's aging management approach for cumulative fatigue damage for components in the ESF systems. In the discussion, the LRA refers to a TLAA in Section 4.3, which states that the applicant determined that components in the ECCS exceed the screening criteria. The applicant evaluated the piping components that exceed the screening criteria for their potential to exceed 7000 thermal cycles in 60 years of plant operation.

The applicant determined that none of the piping components in the ESF system exceed 7000 cycles during the period of extended operation. In RAI 3.2-1, the staff asked the applicant to provide the highest estimated number of thermal cycles and the basis for derivation for each component type identified in Tables 3.2.2-1 through 3.2.2-4 of the LRA for which TLAA—Metal Fatigue Program is the designated AMP. For those components whose material or aging effect is not specified in the GALL Report (designated by notes F and I respectively), the staff asked the applicant to clarify whether it performed the thermal cycle evaluation in accordance with the SRP-LR, Section 4.3.1.1.2. If so, the applicant should state whether its TLAA program is consistent with the SRP-LR; if not, the applicant should explain any differences. The staff also asked the applicant to address how it accounts for unanticipated transients and thermal stratification where applicable in the estimation.

In its response, the applicant stated the following:

> The evaluation of cracking by fatigue was identified as a time-limited aging analysis (TLAA) for selected mechanical components in the containment isolation system (LRA Table 3.2.2-2) and the emergency core cooling system (ECCS) (LRA Table 3.2.2-3). Evaluation of cracking by fatigue was not identified as a TLAA for components in the containment spray system (LRA Table 3.2.2-1) or the containment equalization/hydrogen skimmer system (LRA Table 3.2.2-4).

The applicant clarified that the containment isolation system mechanical components identified as susceptible to cracking from fatigue in LRA Table 3.2.2-2 are limited to non-Class 1 RCS sample line piping and valves associated with containment penetrations 1-CPN-66 and 2-CPN-66, which were designed in accordance with United States of America Standard (USAS) B31.1. License renewal drawings LRA-1-5141 and LRA-2-5141 show the non-Class 1 sample line components associated with CPN-66. Section 4.3.2 of the LRA discusses the evaluation of cracking by fatigue for the non-Class 1 portions of the sample line, which is the subject of RAI 4.3.2-1.

The ECCS mechanical components identified as susceptible to cracking from fatigue in LRA Table 3.2.2-3 include the non-Class 1 residual heat removal (RHR) heat exchanger (HE-17) and RHR pump mechanical seal heat exchanger (HE-32) tubes; RHR pump (PP-35) casings; and RHR system piping, thermowells, tubing, strainer housings, and valves, which are subject to elevated temperatures when used during plant cooldown. License renewal drawings LRA-1-5135A, LRA-1-5143, LRA-2-5135A, and LRA-2-5143 show these non-Class 1 RHR components.

With regard to RHR piping, valves, and other mechanical components designed in accordance with USAS B31.1, the RHR system is restricted to the 200 RCS heatup and cooldown cycles shown in LRA Table 4.3-1. Therefore, RHR mechanical components will not approach 7000 cycles during the period of extended operation.

Section 4.3.2 of the LRA discusses fatigue of the RHR heat exchangers. The tube side of these heat exchangers was designed in accordance with ASME Code, Section III, Class C, and the shell side was designed in accordance with ASME Code, Section VIII, Division 1, for unfired welded pressure vessels. The equipment specification for the RHR heat exchangers requires the supplier to verify that all conditions of ASME Code, Section III, paragraph N-415.1 (i.e., exemption from fatigue for Class 1 components), are satisfied for the transient conditions listed in the equipment specification. Specifically, the RHR heat exchangers must be capable of a step change of tube-side fluid from 29 °C (85 °F) to 176 °C (350 °F) simultaneously with 200 cycles of pressurization to the heat exchanger's tube-side design pressure of 600 psig.

The design transients identified in the heat exchanger specification are consistent with the RCS transients defined in UFSAR Table 4.1-10 for heatups and cooldowns. As described in LRA Section 4.3.1, the assumed number of RCS design transients is acceptable for 60 years, and the fatigue evaluation considered in the original design of the RHR heat exchangers will remain valid during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The RHR pumps were designed in accordance with the Standard of the Hydraulic Institute, USAS B16.5, and ASME Draft Code for Pumps and Valves—1968. There were no fatigue requirements for the design of the RHR pumps, and fatigue is not a TLAA for these pumps.

Section 4.3.1.2, "Generic Safety Issue," of the SRP-LR discusses the effects of reactor coolant environment on component fatigue life. The applicant stated that its review of the SRP-LR determined that the generic safety issue (GSI) discussion in Section 4.3.1.2 does not apply to the non-Class 1 portions of the ESF systems evaluated in LRA Section 3.2 because the scope of the GSI is limited to Class 1 locations identified in NUREG/CR-6260. The thermal cycle evaluations discussed in this RAI response pertain to those performed for USAS B3.1.1 piping, as discussed in SRP-LR, Section 4.3.1.1.2, "ANSI B31.1."

The applicant performed the thermal cycle assessment for USAS B31.1 piping, as described in Section 4.3.1.1.2 of the SRP-LR, for components that operate at temperatures that exceed the screening criteria provided in LRA Section 4.3.2. In addition to considering the 10 CFR 54.21(a) screening criteria, the applicant also screened each mechanical system reviewed for the CNP integrated plant assessment to identify potential metal fatigue TLAAs. This screening entailed identifying non-Class 1 components that may operate at temperatures in excess of 104 °C (220 °F) for carbon steel or 132 °C (270 °F) for austenitic stainless steel during normal or upset conditions. The applicant identified fatigue evaluations of components that exceed the screening criteria as TLAAs. These screening criteria are consistent with those described in Section 4.3.2 of the LRA for St. Lucie Units 1 and 2.

The threshold value of 104 °C (220 °F) for thermal fatigue of carbon steel piping is based on an initial ambient temperature of 21 °C (70 °F) with a minimum temperature differential of 65 °C (150 °F). The threshold value of 132 °C (270 °F) for thermal fatigue of stainless steel piping is based on an initial ambient temperature of 21 °C (70 °F) with a minimum temperature differential of 93 °C (200 °F). These minimum temperature differentials are based on industry-sponsored investigations and evaluations of thermal fatigue in nuclear plant piping systems, as presented in EPRI TR-104534.

The I&M responses to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems" (LRA References 4.3-11 through 4.3-15), as summarized in LRA Section 4.3.1, address thermal stratification in Class 1 portions of systems attached to the RCS.

Section 4.1.4 of the UFSAR describes cyclic load considerations. Components of the RCS were designed to withstand the effects of cyclic loads resulting from reactor system temperature and pressure changes. Normal power changes, reactor trips, and startup and shutdown operations introduce these cyclic loads. Table 4.1-10 of the UFSAR gives the number of thermal and loading cycles used for design purposes. To provide a high degree of integrity for the equipment in the RCS, the transient conditions selected for equipment fatigue evaluation were based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, normal and abnormal load transients, and accident conditions. To a large extent, the specific transient operating conditions considered for equipment fatigue analyses were based on engineering judgment and experience. The transients chosen are representative of transients which prudently should be considered to occur during plant operation and which are sufficiently severe or may occur frequently enough to be of possible significance to component cyclic behavior. This methodology does not account for unanticipated transients. If they occur, the Corrective Action Program identifies them and evaluates their impact on design thermal and loading cycles.

The applicant also identified that the ESF AMR results do not include any Class 1 ESF piping and this piping is included in the RCS pressure boundary. As such, fatigue analysis does not apply to the ESF AMR. The staff finds the applicants response reasonable and acceptable because the applicant has addressed the staff's concerns related to thermal cycle evaluation in accordance with the SRP-LR, in a technically sound and satisfactory manner. Therefore, the staff's concerns described in RAI 3.2-1 are resolved.

RAI 3.2-5

Table 3.2.2-2 of the LRA credits the CNP Bolting and Torquing Activities Program with managing the loss of mechanical closure integrity of carbon steel and stainless steel bolts in an external air environment. In RAI 3.2-5, the staff asked the applicant to discuss how it will manage cracking and loss of preload resulting in the loss of mechanical closure integrity. The staff also asked the applicant to designate the inspection activities in its program that are equivalent to the appropriate ASME Code, Section XI, requirements. In addition, the staff asked the applicant to address how it will manage the aging effects for inaccessible bolts. These include bolts such as those located in cavities or obstructed by other components and devices.

In its response, the applicant stated the following:

> Stress corrosion cracking (SCC) occurs through the combination of high stress, a corrosive environment, and a susceptible material (such as that used in high-strength bolts). CNP piping material specifications do not permit, nor have they historically permitted, high-strength bolting in non-Class 1 systems. Proper lubricants and sealant compounds are used to minimize the potential for SCC. In the aging management reviews, sufficient stress to initiate SCC was assumed if bolting was subject to a corrosive environment. Since bolted closures do not contain high-strength bolting, are not submerged or exposed to lubricants containing contaminants, and are exposed to ambient temperature rather than high-temperature process fluids, cracking is not an aging effect requiring management for non-Class 1 closure bolting in an external air environment. Review of operating experience did not identify problems with cracking of carbon or stainless steel bolting in air environments.

In regard to the loss of preload, the applicant stated, "The Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that loss of mechanical closure integrity as a result of loss of pre-load does not occur."

In addressing the staff's concern about bolting inspection activities that are equivalent to the applicable ASME Code, Section XI requirements, the applicant stated the following:

> The Bolting and Torquing Activities Program, Boric Acid Corrosion Prevention Program, and System Walkdown Program manage loss of mechanical closure integrity for closure bolting as described in LRA Sections B.1.2, B.1.4, and B.1.38, respectively. Visual inspections of bolting for loss of material and loss of mechanical closure integrity in the Boric Acid Corrosion Prevention Program and System Walkdown Program are adequate to assure that the closure bolting can perform its intended function since loss of material (and ultimately loss of mechanical closure integrity) for external surfaces such as closure bolting is a long-term aging effect that would be observed well before aging progressed to the point of loss of intended function. The Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that loss of mechanical closure integrity as a result of loss of preload due to high temperatures does not occur....
>
> The Bolting and Torquing Activities program is a plant-specific program and is not comparable to NUREG-1801, Section XI.M18, "Bolting Integrity," which stipulates the inspection requirements of ASME Code, Section XI. These requirements are included in the Inservice Inspection Program for Class 1, 2, and 3 bolted closures. However, these inspection requirements are focused on identifying the aging effect of cracking. Since cracking is not an aging effect requiring management for non-Class 1 bolted closures, the Inservice Inspection Program is not an applicable aging management program for these components.

With respect to the inaccessible bolting aging management, the applicant stated the following:

> When bolted closures are assembled, proper bolting material and appropriate lubricants and sealants are selected in accordance with EPRI NP-5067, *Good Bolting Practices.* Torque values are monitored when the bolted closure is assembled. Maintenance personnel visually inspect components used in bolted closures to assess their general condition during maintenance. Gaskets, gasket seating surfaces, and fasteners are inspected for damage that would prevent proper sealing. Therefore, the Bolting and Torquing Activities Program manages aging effects for bolting, whether accessible or inaccessible. The Bolting and Torquing Activities Program applies to bolting both inside and outside of containment.

The GALL Report Bolting Integrity Program is a comprehensive program to manage bolted closure integrity. It addresses the loss of material, cracking, and the loss of preload for all bolted closures within the scope of license renewal, including safety related bolting, bolting for nuclear steam supply system (NSSS) component supports, bolting for other pressure-retaining components, and structural bolting. The CNP Bolting and Torquing Activities Program addresses only the loss of preload for bolting subjected to elevated temperatures or significant vibration, such as that due to diesel engine operation. This aging effect was conservatively assumed to be applicable to bolting in systems with temperatures above 204 °C (400 °F), which is below the 371 °C (700 °F) elevated temperature threshold for this aging effect accepted in NUREG-1787, Safety Evaluation Report Related to the License Renewal of the Virgil C. Summer Nuclear Station.

Other CNP programs address different aspects of GALL AMP XI.M18. For example, the CNP Inservice Inspection Program includes the ASME Code, Section XI, requirements for Class 1, 2, and 3 bolted closures. In addition, the Boric Acid Corrosion Prevention Program and System Walkdown Program include periodic inspections of pressure-retaining components (including the closure bolting) for signs of leakage that may be due to the loss of preload, cracking, or the loss of material.

The staff finds the applicant's response reasonable and acceptable because the applicant has clarified how the aging effects of cracking, SCC and the loss of preload would be managed in all safety related bolting. Therefore, the staff's concerns described in RAI 3.2-5 are resolved.

RAI 3.2-12

The GALL Report recommends further evaluation of programs to manage the loss of material due to pitting and crevice corrosion to verify the effectiveness of the Water Chemistry Control Program. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is progressing so slowly that the intended function will be maintained during the period of extended operation. Tables 3.2.2-1, 3.2.2.2, and 3.2.2-3 of the LRA list various carbon steel components in a treated water environment and stainless steel components in a borated water environment with the aging effect of loss of material. The AMP for these components is the Water Chemistry Control Program, but the tables listed above identify no one-time inspection program. However, Appendix B to the LRA (page B-131) discusses a new plant-specific Chemistry One-Time Inspection Program. The program description states that it is comparable to GALL AMP

XI.M32 but is less broad in scope than the GALL program. In RAI 3.2-12, the staff asked the applicant to clarify that the inspections and examinations performed within the scope of its new Chemistry One-Time Inspection Program will verify the effectiveness of the Chemistry Control Program in managing the aging effect of loss of material in the various carbon steel components in a treated water environment and stainless steel components in a borated water environment listed in LRA Tables 3.2.2-1, 3.2.2-2, and 3.2.2-3.

In its response, the applicant stated the following:

> The Generic Aging Lessons Learned (GALL) report [Section XI.M2] identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. Accordingly, in certain cases as identified in the GALL report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring. As discussed in the GALL report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system. NUREG-1801 does not identify stainless steel components in ESF systems as requiring augmentation of the water chemistry program.

The applicant also stated the following:

> ...effectiveness of the chemistry control programs will be verified by the Chemistry One-Time Inspection Program, as described in LRA Section B.1.41. Inspections and examinations performed under this program will verify the effectiveness of chemistry control programs in managing the aging effect of loss of material for carbon steel in a treated water environment and stainless steel in a borated water environment, as specified in NUREG-1801.

The staff finds the applicant's response reasonable and acceptable because the applicant has clarified how the Chemistry One-Time Inspection Program will verify the effectiveness of the Chemistry Control Program. Therefore, the staff's concerns described in RAI 3.2-12 are resolved.

3.2.2.3.1 Containment Spray System

Summary of Technical Information in the Application

In Section 3.2.2.1.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the Containment Spray System components:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- Inservice Inspection - ASME Section XI, Augmented Inspections Program
- Service Water System Reliability Program
- System Walkdown Program
- Water Chemistry Control Program

In Table 3.2.2-1 of the LRA, the applicant provided a summary of AMRs for the Containment Spray System components and identified which AMRs it considered to be consistent with the GALL Report.

Staff Evaluation

The staff reviewed the AMR of the containment spray system component, material, environment, and AERM combinations that the GALL Report does not address. These combinations use notes F through J in LRA Table 3.2.2-1. The staff also reviewed those combinations in Table 3.2.2-1, with notes A through E, for which there are identified emerging issues. The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 3.2.2-1 of the LRA lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR include bolting, eductor, heat exchanger (shell and tubes), heater housing, piping, manifolds, orifices, spray nozzles, thermowells, nozzles, pump casing, tanks, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel components (bolting) in air (external) and outdoor air (external) environments are subject to loss of material and loss of mechanical closure integrity.
- Carbon steel components in air (external) and fresh raw water (internal) are subject to loss of material.
- Stainless steel components in fresh raw water (external) and treated, borated water (internal) environments are subject to fouling and loss of material. Stainless steel components in fresh raw water (external) are also subject to loss of material—wear.
- Stainless steel components in treated, borated water (internal) environments are subject to cracking and loss of material.
- Stainless steel components in untreated, borated water (internal and external) are subject to loss of material.
- Stainless steel components in fresh raw water (external) and treated, borated water (internal) environments are subject to fouling and also to loss of material—wear in fresh raw water (external).
- Carbon steel components with stainless cladding in fresh raw water (external) are subject to cracking, loss of material, and loss of material—wear.
- Cast stainless steel components in treated, borated water (internal) are subject to loss of material.

- Stainless steel components exposed to air (external) and outdoor air (external) environments, as well as cast stainless steel components exposed to air (external) environments, experience no aging effects.

The staff reviewed the information in Section 3.2.2.1.1 and Table 3.2.2-1 in the LRA. During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.2-6 and 3.2-7

Table 3.2.2-1 of the LRA identifies a plant-specific Inservice Inspection Program for managing the aging effect caused by cracking and the loss of material in stainless steel thermowells and valves in a sodium hydroxide environment. The table also identified a plant specific In-service Inspection Program for managing the aging effect caused by cracking and the loss of material in stainless steel tanks in an internal sodium hydroxide environment. The GALL Report does not evaluate this combination of environment, material, and component. In RAIs 3.2-6 and 3.2-7, the staff asked the applicant to discuss the plant-specific inspection methods, including the frequency of inspections and acceptance criteria. The staff also asked the applicant to identify and justify any differences between the plant-specific program and the appropriate ASME Code, Section XI, requirements.

In its response, the applicant stated the following:

> To manage cracking and loss of material of stainless steel thermowells and valves in a sodium hydroxide environment, LRA Table 3.2.2-1 and LRA Section B.1.18 identify an Augmented Inservice Inspection (ISI) Program that specifies volumetric inspections for portions of the containment spray system wetted by sodium hydroxide. Augmented inspections are specified for components that are outside the jurisdiction of ASME Section XI inspection requirements. Augmented inspections use the same non-destructive examination methods used for ASME Section XI inspections on Class 1, 2, or 3 components. The inspections of the stainless steel thermowells and valves in the containment spray system will use ultrasonic techniques, where feasible. The frequency of inspections will be once every 10 years, consistent with ASME Section XI, Subsection IWC, requirements for comparable Class 2 components. Acceptance criteria will be in accordance with the Class 2 acceptance criteria of IWC-3000.

The staff finds the applicant's response to RAI 3.2-6 and RAI 3.2-7 technically sound and acceptable because the applicant's inspection methods, acceptance criteria and frequency of inspections conform to the ASME Section XI requirements. In addition, the inspection frequency is also consistent with operating experience. Therefore, the staff's concerns described in RAIs 3.2-6 and 3.2-7 are resolved.

RAI 3.2-8

Table 3.2.2-1 of the LRA does not identify any AERM for stainless steel tanks in a concrete environment. In RAI 3.2-8, the staff asked the applicant to clarify whether periodic thickness measurements taken specifically at weld locations and at the tank bottom ensure that the integrity of the tank is maintained. If so, the applicant should specify the frequency and method of inspections.

In its response, the applicant stated the following:

> The stainless steel tank exposed to a concrete (external) environment, as indicated in LRA Table 3.2.2-1, is the refueling water storage tank (TK-33), which is depicted on license renewal drawings LRA-1-5144 and LRA-2-5144 at location B4. The tank base is in contact with the concrete pad. The concrete pads are constructed in accordance with American Concrete Institute (ACI) specification 318-63, which results in high quality concrete free of contamination. Therefore, loss of material is not an aging effect requiring management due to the inherent corrosion resistance of stainless steel, alkalinity of concrete, and lack of contamination. Since there are no aging effects requiring management for this external stainless steel surface, periodic thickness measurements are not required.

The staff finds the applicant's response reasonable and acceptable because the applicant has provided a satisfactory explanation for not managing aging effects on the external surface of stainless steel tanks exposed to a concrete environment. Therefore, the staff's concern described in RAI 3.2-8 is resolved.

RAI 3.2-10

The GALL Report recommends a plant-specific AMP for the loss of material due to general, pitting, and crevice corrosion and MIC in carbon steel components exposed to lubricating oil that may be contaminated with water. Similar aging effects (except general corrosion) are possible for copper alloy. The NRC staff considers a periodic inspection program appropriate to manage this aging effect. In RAI 3.2-10, the staff asked the applicant to provide a periodic inspection program in addition to the Oil Analysis Program for aging management of the loss of material due to general (carbon steel), pitting, and crevice corrosion and MIC, or justify not managing this aging effect, for the oil cooler shell in the ECCS (LRA Table 3.2.2-3) exposed to an oil environment.

In its response, the applicant stated the following:

> Loss of material is not an aging effect requiring management for surfaces exposed to lubricating oil unless moisture or contaminants are present. The Oil Analysis Program monitors and controls abnormal levels of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. This is consistent with the previously approved NRC Staff position documented in NUREG-1743, Safety Evaluation Report Related to the License Renewal of Arkansas Nuclear One, Unit 1, Section 3.3.1.4.7.

The response states that the loss of material is not an AERM for surfaces exposed to lubricating oil unless moisture or contaminants are present. In GALL AMP XI.M32, the staff states that where aging effects are not expected to occur but data are insufficient to completely rule out their possibility, a one-time inspection is acceptable to confirm that aging effects are not occurring. An alternate acceptable program may include routine maintenance or a review of repair records. The applicant stated that based on operating experience there is reasonable assurance that the Oil Analysis Program will continue to manage the aging effects of components exposed to lubricating oil; a review of the repair records supports this. The staff finds the applicant's response reasonable and acceptable because the applicant has provided a satisfactory explanation to the staff's concerns relating to the management of aging effects in the oil coolers of the ECCS.

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 of the containment spray system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components of the containment spray system and the staff's concern described in RAI 3.2-10 is resolved.

Aging Management Programs.

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the programs.

Table 3.2.2-1 of the LRA identifies the following AMPs for managing the aging effects described above for the containment spray system:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- Inservice Inspection—ASME Section XI, Augmented Inspection Program
- Service Water System Reliability Program
- System Walkdown Program
- Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.5, 3.0.3.3.6, 3.0.3.2.11, 3.0.3.3.14, and 3.0.3.3.16 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

In RAI 3.2-5, the staff requested that the applicant explain why it did not identify the Bolting and Torquing Activities Program as a required AMP for the containment spray system. In addition, the staff asked the applicant to demonstrate that it will adequately manage the aging effects associated with closure bolting with the Boric Acid Corrosion Prevention, Bolting and Torquing Activities, and System Walkdown Programs, or that it will manage them in a manner equivalent to that described in GALL AMP XI.M18. Section 3.2.2.3 of this SER presents the staff's discussion of this RAI and its resolution by the applicant.

For carbon steel bolting exposed to air, the GALL Report does not address the loss of mechanical closure integrity. In the LRA, for the loss of mechanical closure integrity in carbon steel bolting exposed to ambient air, the applicant proposed to use its Boric Acid Corrosion Prevention (CNP AMP B.1.4) and System Walkdown (CNP AMP B.1.38) Programs. The staff's evaluation of the Boric Acid Corrosion Prevention Program and the System Walkdown Program appears in Sections 3.0.3.2.1 and 3.0.3.3.14 of this SER, respectively.

The staff reviewed existing procedures, as well as the proposed enhancements related to evaluating the extent of degradation and criteria for initiating corrective actions. Because the program will include detailed guidance for inspecting and evaluating the material condition of SCs within the program's scope, and because the guidance will include specific parameters to be monitored and criteria to be used for evaluating their condition, the staff finds that this approach is an acceptable way to manage this aging effect when supplemented by an approved Boric Acid Corrosion Prevention Program. The staff reviewed and accepted the Boric Acid Corrosion Prevention Program as documented in Section 3.0.3.2.1 of this SER.

In the LRA, the applicant stated that no AMP is needed to address aging effects on stainless steel in an environment of air. The applicant did not identify an aging effect for stainless steel components exposed to air (either internal or external). Component types identified include bolting, eductor, heater housing (RWST electric heater), manifold (piping), orifice, piping, pump casing, spray nozzle, tank, thermowell, tubing (instrument piping), and valves. The GALL Report does not identify stainless steel as a material associated with some of these components, and air is not a defined environment for the others.

Loss of material may be an applicable aging effect where stainless steel components are under wet conditions and the components have crevice areas that may be exposed to fluids or have areas where stagnant fluid may be present. The ambient environment for containment spray components does not contain contaminants of sufficient concentration to cause aging effects that require management. Based on industry experience for this combination of material and environment, the staff finds that no AMP is required to manage the loss of material from stainless steel components exposed to air at CNP.

In the LRA, the applicant stated that it will manage the loss of material from stainless steel components in treated, borated water by using the Water Chemistry Control Program. Component types identified include eductor, heater housing (RWST electric heater), heat exchanger tubes, manifold (piping), orifice, piping, pump casing, tank, thermowell, tubing (instrument piping), and valves. On the basis of industry experience that loss of material from stainless steel components in chemically treated, borated water is not significant, the staff finds that management of this aging effect using a water chemistry control program consistent with the GALL Report is sufficient.

In the LRA, the applicant stated that it will manage fouling of stainless steel heater exchanger tubes in treated water by using water chemistry control. The applicant cited a precedent that implies that the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program (CNP AMP B.1.40.3) applies. The staff's evaluation of this program appears in Section 3.0.3.3.16 of this SER. The GALL Report recommends managing loss of material using a program consistent with GALL AMP XI.M21 which more closely corresponds to the Water Chemistry Control—Closed Cooling Water Chemistry Control Program (CNP AMP B.1.40.2). The staff's evaluation of this program appears in Section 3.0.3.2.16 of this SER. Because these Water Chemistry Control Programs are consistent with the recommendations of the GALL Report and each one allows management of fouling, the staff finds that the Water Chemistry Control Programs will adequately manage fouling.

In the LRA, the applicant stated that it will manage fouling from stainless steel containment spray heat exchanger tubes (internal) in treated, borated water by using the Water Chemistry Control Program. Because the Water Chemistry Control Program is consistent with the recommendations of the GALL Report and allows management of fouling, the staff finds this approach acceptable.

In the LRA, the applicant stated that stainless steel piping and valve component types in a nitrogen gas environment are not subject to AERMs. Based on industry experience with this combination of material and environment, the staff finds this acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the containment spray system components that are not addressed by the GALL Report, 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.2.2.3.2 Containment Isolation System

Summary of Technical Information in the Application

In Section 3.2.2.1.2 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the Containment Isolation System components:

- Bolting and Torquing Activities Program
- Boric Acid Corrosion Prevention Program
- Containment Leakage Rate Testing Program
- System Walkdown Program
- Wall Thinning Monitoring Program
- Water Chemistry Control Program

In Table 3.2.2-2 of the LRA, the applicant provided a summary of AMRs for the Containment Isolation System components and identified which AMRs it considered to be consistent with the GALL Report.

Staff Evaluation

The staff reviewed the AMR of the containment isolation system component, material, environment, and AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.2.2-2, except for those with past precedents. The staff also reviewed those combinations in Table 3.2.2-2, with notes A through E, for which emerging issues were identified. The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects

Table 2.3.2-2 of the LRA lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR include bolting, piping, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel components in air (external and internal), condensation (external and internal), fresh raw water (internal), treated water (internal), and nitrogen (internal) environments are subject to loss of material and loss of mechanical closure integrity.

- Stainless steel components in environments of air (internal and external), condensation (external), fresh raw water (internal), treated and borated water (internal and external), and treated and borated water 132 °C (270 °F) and above are subject to loss of material, cracking, and loss of mechanical closure integrity.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.2-2

Table 3.2.2-2 of the LRA does not list any AERM for carbon steel piping with an internal nitrogen environment. In RAI 3.2-2, the staff asked the applicant to discuss the potential for moisture in the internal nitrogen environment and whether it periodically verifies that the environment is moisture-free.

In its response, the applicant stated the following:

> ...the carbon steel piping with an internal nitrogen environment is shown on license renewal drawings LRA-1-5143A and LRA-2-5143A. The nitrogen inside this piping is supplied by the on-site nitrogen supply system shown on license renewal drawing LRA-12-5118B. The nitrogen gas inside the tanks that supply these lines is provided by a vendor as 99.998% pure nitrogen with moisture less than 5.0 parts per million. The nitrogen supply system does not contain compressors that could introduce contaminants such as moisture. Since there is minimal potential for moisture inside the carbon steel pipe associated with these containment penetrations, sampling is not required.

The staff finds the applicant's response reasonable and acceptable because the potential for moisture in the internal nitrogen environment seems unlikely based on the information provided by the applicant. Thus, the staff considers the issue related to this RAI resolved.

RAI 3.2-3

Table 3.2.2-2 of the LRA credits the Containment Leakage Rate Testing Program with managing the loss of material in carbon steel piping in an air (internal) environment. This is a plant-specific program, since the GALL Report does not evaluate a comparable environment for carbon steel piping. In RAI 3.2-3, the staff asked the applicant to perform a one-time inspection in addition to the Containment Leakage Rate Testing Program to identify and mitigate any aging effects resulting from moisture in the internal air of the carbon steel piping.

In its response, the applicant identified the containment isolation system containment penetrations with component types "piping" and "valve" listed in LRA Table 3.2.2-2 that are constructed of carbon steel, contain air, and credit the Containment Leakage Rate Testing Program with managing the loss of material.

The applicant stated the following:

> ...all identified penetrations are used during outages or are capped and are no longer used. During normal operation, these penetrations contain only the air that is trapped internal to the penetration. These penetrations are not exposed to a continuous supply of air that could provide additional moisture and cause a significant loss of material. The internal surfaces could experience minor general corrosion but significant loss of material is not expected due to the limited amount of moisture in the captured air within the penetration piping. Containment leakage rate tests verify that leakage through components that penetrate containment does not exceed allowable rates specified in the technical specification or associated bases. In addition, periodic surveillance tests of the components included as part of the Containment Leakage Rate Testing Program are performed to verify that proper maintenance and repairs are made during the service life of the containment. Negative trends and degraded conditions identified by this program that could be indicative of loss of material would be addressed by the Corrective Action Program. Therefore, the Containment Leakage Rate Testing Program is adequate to manage the aging effect of loss of material for these penetrations, and no one-time inspections are necessary.

The staff finds the applicant's response reasonable and satisfactory because the applicant has provided justification to assure that the loss of material for these penetrations would be minimal and the Containment Leakage Rate Testing Program has adequate provisions to identify any degradation. Therefore, the staff considers RAI 3.2-3 issue resolved.

RAI 3.2-4

Table 3.2.2-2 of the LRA credits the Boric Acid Corrosion Prevention Program with managing the loss of mechanical closure integrity for carbon steel bolts in an external air environment. This AMP relies on the implementation of recommendations in NRC GL 88-05. Since this program addresses components inside the containment, the staff issued RAI 3.2-4 asking the applicant to discuss the management of the loss of mechanical closure integrity of carbon steel bolts outside the containment.

In its response, the applicant stated the following:

> ...the Boric Acid Corrosion Prevention Program manages loss of mechanical closure integrity for carbon steel bolts on which borated reactor water may leak. It includes carbon steel bolts in an external air environment whether inside or outside of containment.

Since the AMP scope goes beyond the GALL Report and covers other leaks besides those from the RCPB, the staff's concern described in RAI 3.2-4 is resolved.

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 of the containment cooling system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that 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

After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.2.2-2 of the LRA identifies the following AMPs for managing the aging effects described above for the containment isolation system:

- Boric Acid Corrosion Prevention Program
- Bolting and Torquing Activities Program
- System Walkdown Program
- Containment Leakage Rate Testing Program
- Water Chemistry Control—Chemistry One-Time Inspection Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.2, 3.0.3.3.14, 3.0.3.1, and 3.0.3.3.17 of this SER, respectively.

In the LRA, for the loss of mechanical closure integrity in carbon steel bolting exposed to ambient air, the applicant proposed to use the Bolting and Torquing Activities (CNP AMP B.1.2), Boric Acid Corrosion Prevention (CNP AMP B.1.4), and System Walkdown (CNP AMP B.1.38) Programs. The staff's evaluation of these programs appears in Sections 3.0.3.3.2, 3.0.3.2.1, and 3.0.3.3.14 of this SER, respectively.

The staff reviewed existing procedures, as well as the proposed enhancements related to evaluating the extent of degradation and criteria for initiating corrective actions. Because the program will include detailed guidance for inspecting and evaluating the material condition of

SCs within the program scope, and because the guidance includes specific parameters to be monitored and criteria to be used for evaluating their condition, the staff finds that this approach is an acceptable way to manage this aging effect when supplemented by approved Bolting and Torquing Activities and Boric Acid Corrosion Prevention Programs.

In the LRA, the applicant stated that no AMP is needed to address aging effects on stainless steel in air (including condensation). This includes bolting, piping, and valve component types. Loss of material may be an applicable aging effect where stainless steel components are under wet conditions and the components have creviced areas that may be exposed to fluids or have areas where stagnant fluid may be present. The environment for containment isolation components does not contain contaminants of sufficient concentration to cause AERMs in stainless steel. Based on industry experience for this combination of material and environment, the staff finds that no program is required to manage the loss of material from stainless steel components exposed to air at CNP.

The applicant in the LRA stated that it will manage the loss of material exposed to lubricating oil by using CNP AMP B.1.23, "Oil Analysis," which is a plant-specific program. This applies to brass, carbon steel, cast iron, copper alloy, and stainless steel. (Glass is also exposed to lubricating oil, but there is no identified AERM for this material.)

The Oil Analysis Program analyzes for contaminants, anomalous particulates, and moisture. In addition, beneficial additives are maintained in lubricating oils. The staff evaluation of this program appears in Section 3.0.3.3.8 of this SER. On the basis of operating experience at CNP, the staff concludes that this preventive program is effective in the management of aging effects in this environment and finds the associated AMRs to be acceptable.

In the LRA, the applicant stated that it will manage cracking of stainless steel components in treated, borated water greater than 132 °C (270 °F) by using water chemistry control. This is proposed for piping and valve component types. The GALL Report suggests a plant-specific program. While the Water Chemistry Control Program is expected to prevent and mitigate aging effects, the staff finds that this may not be sufficient.

The staff asked the applicant to justify the absence of an inspection or monitoring program to confirm the effectiveness of water chemistry control in managing this aging effect or identify the program that will be used to do so. In the related RAI B.1.41-2, the staff asked the applicant to provide a list of components, material types, environments, and aging effects that will be inspected using its Water Chemistry Control—Chemistry One-Time Inspection Program (CNP AMP B.1.41) and to justify that the components selected constitute an adequate sample size to verify the effectiveness of the Water Chemistry Control Program for each aging effect to be managed. Section 3.0.3.3.17 for this SER provides the staff's evaluation of the response to RAI B.1.41-2.

The GALL Report does not address loss of material from components of stainless steel in treated, borated water for the piping and valve component types. The applicant proposed to manage this aging effect using the Water Chemistry Control Program. On the basis of industry experience that loss of material from stainless steel components in chemically treated, borated water is not significant, the staff finds that management of this aging effect using a Water Chemistry Control Program that is consistent with the GALL Report is sufficient.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the containment isolation system components that are not addressed by the GALL Report, 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 applicable UFSAR Supplement program descriptions and concludes that they adequately describe the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.2.2.3.3 Emergency Core Cooling System

Summary of Technical Information in the Application

In Section 3.2.2.1.3 of the LRA, the applicant identified the materials, environments, and AERMs for the ECCS components. The applicant identified the following programs that manage the AERMs for the ECCS components:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- Preventive Maintenance Program
- System Testing Program
- System Walkdown Program
- Water Chemistry Control Program

In Table 3.2.2-3 of the LRA, the applicant provided a summary of AMRs for the ECCS components and identified which AMRs it considered to be consistent with the GALL report.

Staff Evaluation

The staff reviewed the AMR of the ECCS component, material, environment, and AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.2.2-3, except for those for which there are past precedents. The staff also reviewed those combinations in Table 3.2.2-3, with notes A through E, for which emerging issues are identified. The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs with managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.2-3 of the LRA lists individual system components within the scope of license renewal and subject to AMR. The component types that do not rely on the GALL Report for an AMR include bolting, filter housing, flex hose, heat exchanger (shell and bonnet), heat exchanger (tubes), heater housing, manifold (piping), orifices, piping, pump casing, strainer housing, tanks, thermowell, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Cast iron components exposed to a treated water (internal) environment are subject to the aging effect of loss of material. Cast iron components in air (external) environments are subject to loss of material as well.

- Carbon steel components (bolting) in air (external) environments are subject to loss of material and loss of mechanical closure integrity. Carbon steel exposed to a lubricating oil (internal) environment is subject to loss of material.

- Stainless steel components in fresh raw water (internal) environments are subject to loss of material. Stainless steel components in treated water (external), treated, borated water (internal), and treated, borated water greater than 132 °C (270 °F) (internal) environments are subject to fouling, cracking, and loss of material.

- In a treated, borated water (internal) environment, copper alloy components are subject to fouling. Copper alloy components exposed to lubricating oil (external) are subject to fouling. Copper alloys exposed to lubricating oil (internal) are subject to loss of material.

- Carbon steel with stainless steel cladding in air (external) and treated, borated water (internal) environments is subject to loss of material.

- Stainless steel components exposed to air (external) and nitrogen (internal) environments experience no aging effects.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.2-11

Table 3.2.2-3 of the LRA states that the Water Chemistry Control Program will manage loss of material for the copper alloy oil cooler tubes for the pump in a cooling water environment. For this material type and environment, the staff considers selective leaching to be an AERM. In RAI 3.2-11, the staff asked the applicant whether it considered selective leaching to be an aging mechanism for the tubes. If so, the applicant should describe the types of inspections it will use to detect selective leaching in the tubes.

In its response, the applicant stated the following:

> ...the copper alloy tubes identified in LRA Table 3.2.2-3 are part of small shell and tube heat exchangers that provide cooling for the oil lubricating the safety injection (SI) pump bearings and centrifugal charging pump (CCP) bearings and gear assemblies. Component cooling water is supplied through the heat exchanger tubes. The component cooling water system is a closed-loop system treated with corrosion inhibitors....
>
> Selective leaching was identified in the aging management review as one of the mechanisms that could result in the aging effect of loss of material for copper alloy internal surfaces. The Closed Cooling Water Chemistry Control Program

includes preventive measures that manage loss of material, including that due to selective leaching, where applicable. The Chemistry One-Time Inspection Program will verify the effectiveness of the chemistry programs to manage the effects of aging such that components will perform their intended functions for the period of extended operation. In addition, these heat exchangers will be included in the Heat Exchanger Monitoring Program, which will inspect the heat exchangers for degradation using nondestructive examinations, such as eddy current inspections or visual inspections or, if appropriate, the heat exchangers will be replaced. This combination of preventive measures and inspections are adequate to provide reasonable assurance that all aging effects, including selective leaching, will be managed and that the components will perform their pressure boundary intended function during the period of extended operation.

The Heat Exchanger Monitoring Program will include activities to manage loss of material due to selective leaching. Brinell Hardness testing will be performed on selected heat exchanger tubes that are susceptible to selective leaching, when feasible. However, Brinell Hardness testing may not be feasible for some components due to form and configuration (e.g., heat exchanger tubes). In such cases, examinations other than Brinell Hardness testing may be used to identify the presence of selective leaching of material. Other mechanical means, such as scraping or chipping, will provide an effective method for identifying selective leaching.

The staff finds the applicant's response reasonable and acceptable because the applicant has identified satisfactory methods for detecting selective leaching. Therefore, the staff's concern described in RAI 3.2-11 is resolved.

RAI 3.2-13

Table 3.2.2-3 of the LRA lists the loss of material and erosion as AERMs for the flow orifices/elements, but it does not list cracking. The staff considers cracking a possible AERM for flow orifices/elements. In RAI 3.2-13, the staff asked the applicant to describe the flow orifices/elements, their location in the system, and why it does not consider cracking to be an AERM.

In its response, the applicant identified the various restricting orifices and flow-metering orifices in LRA Table 3.2.2-3. These stainless steel components are exposed to water with a temperature below the 60 °C (140 °F) cracking threshold for intergranular attack or SCC. These components are not subject to cracking from thermal fatigue because they are not exposed to the elevated temperatures that are required for this aging effect. Therefore, cracking is not an AERM for these components. The staff finds the applicant's response reasonable and acceptable because the applicant has identified the various flow orifices and their locations in the system and provided adequate assurance that cracking is not likely to occur. Therefore, the staff's concern described in RAI 3.2-13 is resolved.

RAI 3.2-14

Table 3.2.2-3 of the LRA states that a plant-specific Preventive Maintenance Program manages cracking in the pump casing with an internal stainless steel cladding, in a borated water environment. The applicant stated that this cracking is not SCC but is a component-specific cracking resulting from stress concentration. In RAI 3.2-14, the staff asked the applicant to provide information about (a) the inspection frequency of these charging pumps including the bases of the frequency, (b) the operating history of the pumps, and (c) whether it has performed an evaluation of fatigue resulting from pressure cycling to rule out fatigue-cracking as a factor. If so, the applicant should provide that evaluation.

In its response, the applicant stated the following:

(a) The current CCP inspection frequency is once every four fuel cycles. The inspection frequency was based upon the stress analysis and the corrosion rates of carbon steel subjected to boric acid, as described in NRC Information Notice (IN) 80-38, "Cracking in Charging Pump Casing Cladding," and based upon plant-specific inspection results, which are summarized in the following table:

Date	Pump	Results
March 1992	2-PP-50E	No indications that required repairs were found
July 1992	1-PP-50E	Identified and repaired crack indications (1 inch to 8½ inches in length) on discharge side.
August 1995	1-PP-50W	Identified and repaired crack indications on pump inboard and outboard ends.
April 1996	2-PP-50W	No indications that required repairs were found
October 1999	2-PP-50E	Identified and repaired a ¼-inch long linear indication in the pump inlet nozzle.
August 2000	1-PP-50E	Identified and repaired linear indications in the pump inboard and outboard nozzles.
January 2002	2-PP-50W	Identified and repaired two ¼-inch long flaws in the pump inlet nozzle.
May 2002	1-PP-50W	No indications that required repairs were found
May 2003	2-PP-50W	Identified and repaired four indications that reached the carbon steel substrate under the cladding at the pump inlet nozzle.

(b) A review of condition reports and inservice testing results since 1999 did not reveal any significant events related to operation of the CCPs. Significant events related to operation of the CCPs prior to 1999 are summarized below:

Licensee Event Report (LER) 50-315/77-18, dated May 3, 1977, reported that the Unit 1 west CCP failed due to a broken shaft. The rotating element was replaced and the pump returned to service. The failure was described as a clean break occurring under the eleventh stage impeller with indications that fatigue was the failure mechanism. The vendor traced the failure to a bad heat used in the manufacture of the shafts.

LER 50-315/77-20, dated June 1, 1977, reported that the Unit 1 east CCP shaft broke between the third and fourth stage impellers. The break appeared to be a fatigue failure. The vendor traced the failure to a bad heat used in the manufacture of the shafts.

LER 82-032/03L-0, dated May 3, 1982, reported that the Unit 2 east CCP was removed from service during the previous month to replace the mechanical seal.

LER 82-046/03L-0, dated July 6, 1982, reported that the Unit 1 east CCP was declared inoperable as a result of excessive vibration. The pump rotating assembly was replaced. During repairs, pitting erosion/corrosion through the stainless steel cladding and into the carbon steel pump case was identified at the suction and discharge nozzles. The affected areas were ground out and repaired by welding.

LER 83-090/03L-0, dated September 20, 1983, reported that during an ECCS flow balance, the Unit 1 west CCP minimum flow was below the minimum allowable rate. NRC inspection report 50-31583-14, dated October 5, 1983, documented that the pump rotating element was replaced.

LER 86-012-01, dated December 4, 1986, reported that, with the Unit 2 west CCP operating, attempts to balance system flow failed due to degraded performance of the pump. The pump rotating element was replaced.

LER 93-006-00, dated August 9, 1993, reported that the Unit 2 west CCP was declared inoperable due to high vibration. Upon disassembly of the rotor assembly, the pump shaft was found to be cracked. The pump rotor assembly was replaced with a rebuilt assembly.

(c) Fatigue evaluations for pressure cycling have not been performed, since cladding failure of the charging pump cladding is a defect caused by stress concentrations, as discussed in NRC IN 80-38, and is not a fatigue issue.

Based on a review of the operating history of the pump, the staff finds that the cracking in the pump is most likely not the result of SCC but is a component-specific cracking resulting from stress concentration, as the applicant contended. The staff therefore finds the applicant's response acceptable, and the staff's concerns described in RAI 3.2-14 are 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 RAI, the staff finds that the aging effects of the above ECCS component types that are not addressed in the GALL Report and the specific component types that are within the scope of review are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omissions of aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the ECCS.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.2.2-3 of the LRA identifies the following AMPs for managing the aging effects described above for the SFP system component types that are within the scope of review:

- Boric Acid Corrosion Prevention Program
- System Walkdown Program
- Water Chemistry Control—Chemistry One-Time Inspection Program
- Oil Analysis Program
- Preventive Maintenance Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.14, 3.0.3.3.17, 3.0.3.3.8 and 3.0.3.3.10 of this SER, respectively.

In the LRA, the applicant stated that it will manage loss of mechanical closure integrity in high-temperature or high-pressure systems for carbon steel bolting exposed to ambient air by using its Bolting and Torquing Activities (CNP AMP B.1.2), Boric Acid Corrosion Prevention (CNP AMP B.1.4), and System Walkdown (CNP AMP B.1.38) Programs. The staff's evaluation of these programs appears in Sections 3.0.3.3.2, 3.0.3.2.1, and 3.0.3.3.14 of this SER, respectively.

The staff reviewed existing procedures, as well as the proposed enhancements related to evaluating the extent of degradation and criteria for initiating corrective actions. Because the program will include detailed guidance for inspecting and evaluating the material condition of SCs within the program scope, and because the guidance includes specific parameters to be monitored and criteria to be used for evaluating their condition, the staff finds that this approach is an acceptable way to manage this aging effect when supplemented by approved Bolting and Torquing Activities and Boric Acid Corrosion Prevention Programs.

For stainless steel exposed to ambient air, the applicant identified no AERMs. The component types affected are bolting, flex hose, heater housing, orifice, manifold, piping, pump casing strainer housing, tank, thermowell, tubing, and valves. No aging effects are identified for piping and valves exposed to nitrogen (gas). Because there are no identified AERMs, and because this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air and nitrogen to be acceptable.

In the LRA, the applicant stated that it will use its Oil Analysis Program (CNP AMP B.1.23) to manage the loss of material from carbon steel filter housing, heat exchanger shell, piping, pump casing, and tank; copper alloy heat exchanger shell and tubes, piping, and valves; stainless steel piping; and cast iron pump casing component types. Section 3.0.3.3.8 of this SER documents the staff evaluation of this program. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages the loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that the GALL Report does not address loss of material from components of stainless steel in treated, borated water for the flex hose, heat exchanger tubes, heater housing, manifold, orifice, piping, pump casing, strainer housing, tank, thermowell, tubing, or valve component types, nor for pump casing and tanks clad with stainless steel. The applicant proposed to manage this aging effect using the Water Chemistry Control Program. On the basis of industry experience showing that loss of material from stainless steel components in chemically treated, borated water is not significant, the staff finds that management of this aging effect using a water chemistry control program consistent with the GALL Report is sufficient.

The applicant in the LRA did not identify any AERMs for copper alloy heat exchanger, piping, and valve component types exposed to ambient air. Based on industry experience for this combination of material and environment, the staff finds this to be acceptable.

In the LRA, the applicant stated that it will manage cracking of stainless steel components in treated, borated water greater than 132 °C (270 °F) by using water chemistry control. This is proposed for heat exchanger tubes, manifold, piping, pump casing, strainer housing, thermowell, tubing, and valve component types. The GALL Report suggests a plant-specific AMP. While the Water Chemistry Control Program is expected to prevent and mitigate aging effects, the staff finds that its use alone may not be sufficient.

The staff asked the applicant to justify the absence of an inspection or monitoring program to confirm the effectiveness of water chemistry control in managing this aging effect or to identify the program that it will use to do so. In the related RAI B.1.41-2, the staff asked the applicant to provide a list of components, material types, environments, and aging effects that it will inspect using its Water Chemistry Control—Chemistry One-time Inspection Program (CNP AMP B.1.41) and to justify that the components selected constitute an adequate sample size to verify the effectiveness of the Water Chemistry Control Program for each aging effect to be managed. Section 3.0.3.3.17 for this SER provides the staff's evaluation of the response to RAI B.1.41-2.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the ECCS components that are not addressed by the GALL Report and those specific component types that are within the scope of review, 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 applicable UFSAR Supplement program descriptions and concludes that they adequately describe the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.2.2.3.4 Containment Equalization/Hydrogen Skimmer System

Summary of Technical Information in the Application

In Section 3.2.2.1.4 of the LRA, the applicant identified the materials, environments, and AERMs for the Containment Equalization / Hydrogen Skimmer (CEQ) System components .

The applicant identified the following programs that manage the AERMs for the CEQ system components:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- System Walkdown Program
- Water Chemistry Control Program

In Table 3.2.2-4 of the LRA, the applicant provided a summary of AMRs for the Containment Equalization / Hydrogen Skimmer components and identified which AMRs it considered to be consistent with the GALL report.

<u>Staff Evaluation</u>

The staff reviewed the AMR of the CEQ system component, material, environment, and AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.2.2-4, except for those for which there are past precedents. The staff also reviewed those combinations in Table 3.2.2-4, with notes A through E, for which emerging issues are identified. The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.2-4 of the LRA lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR include bolting, damper housing, piping, valves, ductwork, fan housing, and heat exchanger.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel components in air (external) environments are subject to loss of material and loss of mechanical closure integrity.

- Stainless steel components in air (external and internal) and condensation (internal) environments experience no aging effects.

- Copper alloy pressure boundary components exposed to external air are subject to loss of material—wear.

- Copper alloys exposed internally to treated water are subject to erosion and loss of material.

During its review, the staff determined that it needed additional information to complete its evaluation.

The applicant determined that none of the piping components in the ESF system will exceed 7000 cycles during the period of extended operation. In RAI 3.2-1, the staff asked the applicant to provide the highest estimated number of thermal cycles and the basis for identification for each component type in Tables 3.2.2-1 through 3.2.2-4 of the LRA for which the TLAA—Metal Fatigue Program is the designated AMP. For those components for which the GALL Report does not specify material or aging effect (designated as notes F and I respectively), the staff asked the applicant to clarify whether it performs the thermal cycle evaluation in accordance with SRP-LR, Section 4.3.1.1.2. If so, the applicant should state whether its TLAA program is consistent with the GALL Report, and if not, it should explain any differences. The staff also asked the applicant to address how its estimates account for unanticipated transients and thermal stratification, where applicable.

In its response, the applicant stated the following:

> The evaluation of cracking by fatigue was identified as a time-limited aging analysis (TLAA) for selected mechanical components in the containment isolation system (LRA Table 3.2.2-2) and the emergency core cooling system (ECCS) (LRA Table 3.2.2-3). Evaluation of cracking by fatigue was not identified as a TLAA for components in the containment spray system (LRA Table 3.2.2-1) or the containment equalization/hydrogen skimmer system (LRA Table 3.2.2-4).

Section 3.2.2.3 of this SER discusses the applicant's response to RAI 3.2-1 in further detail.

Aging Management Programs

Table 3.2.2-4 of the LRA identifies the following AMPs for managing the aging effects described above for the hydrogen control system:

- Boric Acid Corrosion Prevention Program
- Heat Exchanger Monitoring Program
- Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program
- System Walkdown Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.5, 3.0.3.3.16, and 3.0.3.3.14 of this SER, respectively.

In the LRA, the applicant stated that it will manage the loss of mechanical closure integrity in carbon steel bolting exposed to ambient air by using its Boric Acid Corrosion Prevention (CNP AMP B.1.4) and System Walkdown.(CNP AMP B.1.38) Programs. The staff's evaluation of these programs appears in Section 3.0.3.2.1 and 3.0.3.3.14 of this SER, respectively.

The staff reviewed existing procedures, as well as the proposed enhancements related to evaluating the extent of degradation and criteria for initiating corrective actions. Because the program will include detailed guidance for inspecting and evaluating the material condition of SCs within the program scope, and because the guidance includes specific parameters to be monitored and criteria to be used for evaluating their condition, the staff finds that this approach is an acceptable way to manage this aging effect when supplemented by an approved Boric Acid Corrosion Prevention Program.

In the LRA, the applicant identified no AERMs for stainless steel bolting or copper-alloy heat exchanger component types exposed to ambient air. Because there are no identified AERMs, and because this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air and nitrogen to be acceptable. The staff reviewed all other AMRs assigned in Tables 3.2.2-1 through 3.2.2-4 of the LRA and finds them to be acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the CEQ system components that are not addressed by the GALL Report, 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 applicable UFSAR Supplement program descriptions and concludes that they adequately describe the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.2.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the ESF system components and component groups that are within the scope of license renewal and subject to an AMR 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).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups associated with the following systems:

- spent fuel pool system
- essential service water system
- component cooling water system
- compressed air systems
- chemical and volume control system
- heating, ventilation, and air conditioning systems
- fire protection system
- emergency diesel generator system
- security diesel system
- postaccident containment hydrogen monitoring system
- miscellaneous systems in scope for 10 CFR 54.4(a)(2)

3.3.1 Summary of Technical Information in the Application

In Section 3.3 of the LRA, the applicant provided the results of the AMR of the auxiliary systems components and component types listed in Tables 2.3.3-1 through 2.3.3-11 of the LRA. The applicant also listed the materials, environments, AERMs, and AMPs associated with each system.

In Table 3.3.1, "Summary of Aging Management Programs for the Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," of the LRA, the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the auxiliary systems components and component types. In Section 3.3.2.2 of the LRA, the applicant provided information concerning Table 3.3.1 components for which the GALL Report recommends further evaluation.

3.3.2 Staff Evaluation

The staff reviewed Section 3.3 of the LRA to understand the applicant's review process and to determine whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the auxiliary systems components that are within the scope of license renewal and subject to an AMR 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 performed an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL AMRs. Section 3.3.2.1 of this SER summarizes the staff's audit findings.

The staff also audited those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's additional evaluations are consistent with the acceptance criteria in Section 3.3.3.2 of the SRP-LR. Section 3.3.2.2 of this SER summarizes the staff's audit findings.

The staff conducted a technical review of the remaining AMRs that are not consistent with the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects and listed the aging effects appropriate for the combination of materials and environments specified. Section 3.3.2.3 of this SER documents the staff's review findings.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they adequately describe the programs credited with managing or monitoring aging for the auxiliary systems and associated components.

Table 3.3-1 below summarizes 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 for Auxiliary Systems Components 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 (Item Number 3.3.1-1)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Not applicable	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Linings in spent fuel cooling and cleanup system; seals and collars in ventilation systems (Item Number 3.3.1-2)	Hardening, cracking, and loss of strength due to elastomer degradation; loss of material due to wear	Plant specific	Not applicable for spent fuel cooling systems. Preventive Maintenance Program (B.1.25); Service Water System Reliability Program (B.1.29); Fire Protection Program (B.1.11)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.2)
Components in load handling, chemical and volume control system (PWR), and reactor water cleanup and shutdown cooling systems (older BWR) (Item Number 3.3.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 52.21c)	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.3)
Heat exchangers in reactor water cleanup system (BWR); high-pressure pumps in chemical and volume control system (PWR) (Item Number 3.3.1-4)	Crack initiation and growth due to SCC or cracking	Plant specific	Preventive Maintenance Program (B.1.25)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in ventilation systems, diesel fuel oil system, and EDG systems; external surfaces of carbon steel components (Item Number 3.3.1-5)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant specific	System Walkdown Program (B.1.38); System Testing Program (B.1.37); Service Water System Reliability Program (B.1.29); Preventive Maintenance Program (B.1.25); Fire Protection Program (B.1.11)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.5)
Components in RCP oil collection system of fire protection (Item Number 3.3.1-6)	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-Time Inspection	Boric Acid Corrosion Prevention Program (B.1.4); Preventive Maintenance Program (B.1.25)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.6)
Diesel fuel oil tanks in diesel fuel oil system and EDG system (Item Number 3.3.1-7)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel Oil Chemistry and One-Time Inspection	Diesel Fuel Monitoring Program (B.1.10)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.7)
Heat exchangers in chemical and volume control system (Item Number 3.3.1-9)	Crack initiation and growth due to SCC and cyclic loading	Water Chemistry and plant-specific verification program	Water Chemistry Control Program (B.1.40); Heat Exchanger Monitoring Program (B.1.13); Water Chemistry Control—Chemistry One-Time Inspection Program (B.1.41)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.9)
Neutron-absorbing sheets in spent fuel storage racks (Item Number 3.3.1-10)	Reduction of neutron-absorbing capacity and loss of material due to general corrosion (boral, boron steel)	Plant specific	Boral Surveillance Program (B.1.3); Water Chemistry Control Program (B.1.40)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.10)
New fuel rack assembly (Item Number 3.3.1-11)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Neutron-absorbing sheets in spent fuel racks (Item Number 3.3.1-12)	Reduction of neutron-absorbing capacity due to Boraflex degradation	Boraflex Monitoring	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Spent fuel storage racks and valves in spent fuel pool cooling and cleanup (Item Number 3.3.1-13)	Crack initiation and growth due to SCC	Water Chemistry	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Closure bolting and external surfaces of carbon steel and low-alloy steel components (Item Number 3.3.1-14)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in or serviced by closed-cycle cooling water system (Item Number 3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Closed-Cycle Cooling Water System	Water Chemistry Control—Closed Cooling Water Chemistry Control Program (B.1.40.2)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Cranes including bridge and trolleys and rail system in load handling system (Item Number 3.3.1-16)	Loss of material due to general corrosion and wear	Overhead Heavy Load and Light Load Handling Systems	Structures Monitoring—Crane Inspection Program (B.1.33)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in or serviced by open-cycle cooling water systems (Item Number 3.3.1-17)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and boifouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Service Water System Reliability Program (B.1.29); System Testing Program (B.1.37); Water Chemistry Control Program (B.1.40)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Buried piping and fittings (Item Number 3.3.1-18)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried Piping and Tank Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection Program (B.1.6); System Testing Program (B.1.37)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1) Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.11)
Components in compressed air system (Item Number 3.3.1-19)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	Containment Leakage Rate Testing Program (B.1.8)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components (doors and barrier penetration seals) and concrete structures in fire protection (Item Number 3.3.1-20)	Loss of material due to wear; hardening and shrinkage due to weathering	Fire Protection	Fire Protection Program (B.1.11)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in water-based fire protection (Item Number 3.3.1-21)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling	Fire Water System	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in diesel fire system (Item Number 3.3.1-22)	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	Diesel Fuel Monitoring Program (B.1.10)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Tanks in diesel fuel oil system (Item Number 3.3.1-23)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Carbon Steel Tanks	System Walkdown Program (B.1.38)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Closure bolting (Item Number 3.3.1-24)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC	Bolting Integrity	Bolting and Torquing Activities Program (B.1.2); System Walkdown Program (B.1.38)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components (aluminum, bronze, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink (Item Number 3.3.1-29)	Loss of material due to selective leaching	Selective Leaching of Materials	Service Water System Reliability Program (B.1.29); Water Chemistry Control Program (B.1.40)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Fire barriers, walls, ceilings, and floors in fire protection (Item Number 3.3.1-30)	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	Not applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

The staff's review of the auxiliary systems and associated components followed one of several approaches. One approach, documented in Section 3.3.2.1 of this SER, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.3.2.2 of this SER, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.3.2.3 of this SER, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are not consistent with the GALL Report or that are not addressed in the GALL Report. Section 3.0.3 of this SER documents the staff's review of AMPs that are credited with managing or monitoring aging effects of the auxiliary systems components.

3.3.2.1 Aging Management Evaluations That Are Consistent with the GALL Report, for Which No Further Evaluation Is Required

Summary of Technical Information in the Application

In Section 3.3.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the auxiliary systems components:

- Boral Surveillance Program
- Water Chemistry Control Program
- Service Water System Reliability Program
- System Walkdown Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- Containment Leakage Rate Testing Program
- Instrument Air Quality Program
- Preventive Maintenance Program
- Boric Acid Corrosion Prevention Program
- System Testing Program
- Bolting and Torquing Activities Program
- Diesel Fuel Monitoring Program
- Fire Protection Program
- Buried Piping Inspection Program
- Flow-Accelerated Corrosion Program

Staff Evaluation

In Tables 3.3.2-1 through 3.3.2-11 of the LRA, the applicant summarized the AMRs for the auxiliary systems components and identified which AMRs it considered to be consistent with the GALL Report.

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 does not recommend further evaluation, the staff performed an audit and review to determine whether the GALL Report evaluation bounded the plant-specific components contained in these GALL Report component groups.

The applicant provided a note for each AMR line item. The notes describe the alignment of the information in the tables with the information in the GALL Report. The staff audited those AMRs with notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different but still consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different but still consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff determined whether the AMR line item of the different component is applicable to the component under review. The staff verified that it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff reviewed the information provided in the LRA and program bases documents, which are available at the applicant's engineering office. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL AMRs. The following sections discuss the staff evaluation.

3.3.2.1.1 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

In the LRA, the applicant stated that it will manage loss of material and cracking for stainless steel, carbon steel, and copper alloy exposed to treated water in the CCW system with its Water Chemistry Control—Closed Cooling Water Chemistry Control Program (CNP AMP B.1.40.2). The applicant stated that this program is consistent with GALL AMP XI.M21, with exceptions. Section 3.0.3.2.16 of this SER documents the staff evaluation of this program.

The GALL Report recommends, in addition to water chemistry control, performance monitoring and functional testing of components managed with this program. The staff asked the applicant to provide justification or a commitment to apply an appropriate testing and/or monitoring program to manage these aging effects. In related RAI B.1.41-2, the staff asked the applicant to provide a list of components, material types, environments, and aging effects that will be inspected using the Water Chemistry Control—Chemistry One-Time Inspection Program (CNP AMP B.1.41) and to justify that the components selected are an adequate sample size to verify the effectiveness of the Water Chemistry Control Program for each aging effect to be managed (see Section 3.0.3.3.17 of this SER for the staff's evaluation of the responses to this RAI).

In the LRA, the applicant stated that it will manage the loss of material from copper alloy components exposed to raw water in the HVAC systems by using its Service Water System Reliability (CNP AMP B.1.2). Section 3.0.3.2.11 of this SER documents the staff's evaluation of this program. The GALL Report suggests the use of programs consistent with GALL AMP XI.M20 and GALL AMP XI.M33. The latter program recommends both visual inspection and hardness testing to monitor this aging effect. The applicant has not identified how the Service Water System Reliability Program will adequately monitor this aging effect.

By letter dated May 6, 2004, the staff asked the applicant, in RAI 3.3.2-2, to provide justification for excluding a hardness measurement from the Service Water System Reliability Program to detect selective leaching (see Section 3.3.2.3.2 for the staff's evaluation of the responses to this RAI).

3.3.2.1.2 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Biofouling; Buildup of Deposit Due to Biofouling

The applicant credited the Service Water System Reliability Program with managing loss of material in stainless steel, elastomer, carbon steel, copper alloy, and cast iron exposed to fresh, raw water (internal) in the ESW system. The Service Water System Reliability Program takes exception to the GALL AMP requirements concerning the lining or coating of components. The applicant stated that components are lined or coated only when necessary to protect underlying metal surfaces. The staff found this acceptable. However, Section B.1.29 of the LRA indicates loss of material only for the enhancement of the program for the 8-inch expansion joints in the ESW supply lines to the EDG heat exchangers, and not for any other component or material.

On the basis of its audit and review, the staff determined that for all other AMRs not requiring further evaluation, as identified in LRA Table 3.3.1 (Table 1), the applicant's references to the GALL Report are acceptable and no further staff review is required.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Conclusion</u>

The staff has verified the applicant's claim of consistency with the GALL Report. The staff has also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL

Report, are consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for these components so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

On the basis of its audit and review, the staff concludes that the applicant has demonstrated that it will adequately manage the effects of aging 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).

3.3.2.2 Aging Management Evaluations That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application

In Section 3.3.2.2 of the LRA, the applicant provided further evaluation of aging management as recommended by the GALL Report for auxiliary systems. The applicant provided information concerning how it will manage the following aging effects:

- loss of material due to general, pitting, and crevice corrosion
- hardening and cracking or loss of strength due to elastomer degradation or loss of material due to wear
- cumulative fatigue damage
- crack initiation and growth due to cracking or stress-corrosion cracking
- loss of material due to general, microbiologically influenced, pitting, and crevice corrosion
- loss of material due to general, galvanic, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and biofouling
- crack initiation and growth due to stress-corrosion cracking and cyclic loading
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion

Staff 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 addresses the issues that were further evaluated. In addition, the staff reviewed the applicant's additional evaluations against the criteria contained in Section 3.3.2.2 of the SRP-LR. The staff's audit and review report gives details of the staff's evaluation.

The GALL Report indicates that further evaluation is necessary for the aging effects described in the following sections of this SER.

3.3.2.2.1 Loss of Material due to General, Pitting, and Crevice Corrosion

In LRA Section 3.3.2.2.1, the applicant addressed the loss of material in components of the SFP and cleanup system.

The applicant stated that the SFP cooling components do not provide any intended function within the scope of license renewal. Aging management of the fuel pool assures pool inventory, which, in turn, assures cooling. Section 3.5.2.2 of this report evaluates this along with the auxiliary building.

Because the spent fuel cooling components do not provide any intended function that requires aging management, the staff finds this to be acceptable.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for components of the SFP system subject to the loss of material so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.2 Hardening and Cracking or Loss of Strength due to Elastomer Degradation or Loss of Material Due to Wear

In LRA Section 3.3.2.2.2, the applicant addressed the potential for the degradation of elastomers in collars and seals in spent fuel cooling systems and ventilation systems. Section 3.3.2.2.2 of the SRP-LR states that hardening and cracking due to elastomer degradation could occur in elastomer linings of the filter, valve, and ion exchangers in SFP cooling and cleanup systems. Hardening and loss of strength due to elastomer degradation could occur in the collars and seals of the duct and in the elastomer seals of the filters in the control room area, auxiliary and radwaste area, and primary containment heating ventilation systems and in the collars and seals of the duct in the diesel generator building ventilation system. Loss of material due to wear could occur in the collars and seals of the duct in the ventilation systems. The GALL Report recommends further evaluation to ensure adequate management of these aging effects.

The applicant stated that the SFP system contains no components with elastomers that are subject to an AMR. For the ventilation systems, the applicant uses the plant-specific AMP B.1.25, "Preventive Maintenance," to manage degradation of elastomers. Section 3.0.3.3.10 of this SER documents the staff's evaluation of this program. For other systems, the applicant uses one of three programs to manage elastomer degradation—the Preventive Maintenance Program (CNP AMP B.1.25), the Service Water System Reliability Program (CNP AMP B.1.29), or the Fire Protection Program (CNP AMP B.1.11). Sections 3.0.3.2.5 and 3.0.3.2.6 (for the Fire Protection Program) and Section 3.0.3.2.11 (for the Service Water System Reliability Program) of this SER document the staff's evaluation of these programs.

RAI 3.3.2-3

The staff requested clarification of the method(s) used to monitor a change in material properties of elastomers in the ventilation systems. Material properties that could affect the performance of elastomers (e.g., hardness, flexibility) are not directly measured. By letter dated August 20, 2004, in RAI 3.3.2-3, the staff asked the applicant to provide a technical basis for the conclusion that degradation of elastomers will be detected before a loss of intended function of the component occurs or to explain why the elastomers are not subject to hardening and flexibility aging effects.

In its response dated September 2, 2004, the applicant stated that hardness and flexibility are not critical properties for maintaining the pressure boundary intended function. The applicant further stated that should the elastomer become excessively hard or brittle, visible cracking would result, which the applicant would detect and correct before degradation and loss of intended function would occur. Finally, the applicant stated that it will perform the visual examinations of elastomer components of ventilation systems at an inspection interval sufficient to identify degradation before a loss of pressure boundary function would occur.

On the basis of its review of the applicant's response to RAI 3.3.2-3, the staff finds that the applicant demonstrated that it will adequately manage hardening and cracking or loss of strength due to elastomer degradation of ventilation system components so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.3 Cumulative Fatigue Damage

As stated in the SRP-LR, fatigue is a TLAA as defined in 10 CFR 54.3. The TLAAs must be evaluated in accordance with 10 CFR 54.21(c)(1). Section 4.3 of this SER documents the staff's review of the applicant's evaluation of this TLAA. In performing this review, the staff followed the guidance in Section 4.3 of the SRP-LR.

3.3.2.2.4 Crack Initiation and Growth due to Cracking or Stress-Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR Section 3.3.2.2.4.

In LRA Section 3.3.2.2.4, the applicant addressed the potential for cracking in the high-pressure pumps of the CVCS.

Section 3.3.2.2.4 of the SRP-LR addresses crack initiation and growth due to cracking in the high-pressure pump in the CVCS. The GALL Report recommends further evaluation to ensure adequate management of these aging effects.

The applicant used the plant-specific Preventive Maintenance Program (CNP AMP B.1.25) to manage cracking of the charging pump casings. Section 3.0.3.3.10 of this SER documents the staff's evaluation of this program. This program was evaluated as an acceptable response to NRC IN 80-38 for monitoring this aging effect, and on that basis, it is acceptable to the staff.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.5 Loss of Material due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

In LRA Section 3.3.2.2.5, the applicant addressed the loss of material from corrosion that could occur on internal and external surfaces of components exposed to air and the associated range of atmospheric conditions.

Section 3.3.2.2.5 of the SRP-LR states that the loss of material due to general, pitting, and crevice corrosion could occur in the piping and filter housing and supports in the control room area and the auxiliary and radwaste area; in the primary containment heating and ventilation systems; in the piping of the diesel generator building ventilation system; in the aboveground piping and fittings, valves, and pumps in the diesel fuel oil system; and in the diesel engine starting air, combustion air intake, and combustion air exhaust subsystems in the EDG system. Loss of material due to general, pitting, and crevice corrosion and MIC could occur in the duct fittings, access doors, closure bolts, equipment frames, and housing of the duct; loss of material due to pitting and crevice corrosion could occur in the heating/cooling coils of the air handler heating/cooling; and loss of material due to general corrosion could occur on the external surfaces of all carbon steel SCs, including bolting exposed to operating temperatures less than 100 °C (212 °F) in the ventilation systems. The GALL Report recommends further evaluation to ensure adequate management of these aging effects.

For managing loss of material from surfaces exposed to air and outdoor air, the applicant credited the System Walkdown Program (CNP AMP B.1.38), evaluated in Section 3.0.3.3.14 of this SER; the System Testing Program (CNP AMP B.1.37), evaluated in Section 3.0.3.3.13; the Service Water System Reliability Program (CNP AMP B.1.29), evaluated in Section 3.0.3.2.11; and the Preventive Maintenance Program (CNP AMP B.1.25), evaluated in Section 3.0.3.3.10. The applicant uses its Fire Protection Program (CNP AMP B.1.11) to manage the loss of material for internal surfaces of the FP system. Sections 3.0.3.2.5 and 3.0.3.2.6 of this SER document the staff's evaluation of Fire Protection Programs.

The staff reviewed CNP operating experience and confirmed that the applicant had exploited sufficient opportunities for inspection. Because the inspection guidance provided assurance that the applicant would identify the presence and extent of these aging effects, the staff finds management of this aging effect to be acceptable.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Loss of Material due to General, Galvanic, Pitting, and Crevice Corrosion

In LRA Section 3.3.2.2.6, the applicant addressed further evaluation of programs to manage the loss of material in the RCP oil collection system to verify the effectiveness of the Fire Protection Program.

Section 3.3.2.2.6 of the SRP-LR states that loss of material due to general, galvanic, pitting, and crevice corrosion could occur in tanks, piping, valve bodies, and tubing in the RCP oil collection system in FP. The Fire Protection Program relies on a combination of visual and volumetric examinations in accordance with the guidelines of Appendix R to 10 CFR Part 50 and BTP 9.5-1 to manage the loss of material from corrosion. However, corrosion may occur at locations where water from washdowns may accumulate. Therefore, the applicant should verify the effectiveness of the program to ensure that corrosion is not occurring.

The GALL Report recommends further evaluation of programs to manage the loss of material due to general, galvanic, pitting, and crevice corrosion to verify the effectiveness of the program. A one-time inspection of the bottom half of the interior surface of the tank of the RCP oil collection system 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. This inspection would be part of a program consistent with GALL AMP XI.M32.

In the LRA, the applicant stated that it will use the plant-specific Preventive Maintenance Program (CNP AMP B.1.25) and, consistent with the GALL Report with enhancements, its Boric Acid Corrosion Prevention Program (CNP AMP B.1.4) to manage the loss of material in lieu of the one-time inspection. Sections 3.0.3.3.10 and 3.0.3.2.1, respectively, of this SER document the staff's evaluation of the Preventive Maintenance and Boric Acid Corrosion Prevention Programs. Because these programs will afford an opportunity to inspect similar material in this environment, the staff finds that they will allow adequate verification of the effectiveness of the management of the loss of material due to general, pitting, galvanic, and crevice corrosion.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Biofouling

In LRA Section 3.3.2.2.7, the applicant addressed further evaluation of programs to manage the loss of material in the diesel fuel oil system to verify the effectiveness of the Diesel Fuel Monitoring Program.

Section 3.3.2.2.7 of the SRP-LR states that the loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling could occur on the internal surface of tanks in the diesel fuel oil system and that loss of material due to general, pitting, and crevice corrosion and MIC could occur in the tanks of the diesel fuel oil system in the EDG system. The existing AMP relies on the Fuel Oil Chemistry Program for monitoring and controlling fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709, and D2276 to manage the loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the Chemistry Control Program is necessary to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion/biofouling to verify their effectiveness. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component will maintain its intended function during the period of extended operation.

The GALL Report recommends programs consistent with GALL AMP XI.M30 and XI.M32 for management of this aging effect.

The applicant used CNP AMP B.1.10, "Diesel Fuel Monitoring," evaluated in Section 3.0.3.2.4 of this SER, to manage the loss of material for the diesel fuel oil system. This program also provides for the periodic inspection of the fuel oil tanks. The applicant took exception to ultrasonic testing of the diesel fuel oil tank, which addresses the one-time inspection recommendation in the GALL Report.

During the audit, the staff requested a basis for the exception to ultrasonic testing. In response, the applicant provided the results of ultrasonic testing that had already been performed and the basis for concluding that the management of the aging effect will maintain the intended function beyond the period of extended operation. After reviewing the data and the basis, the staff finds that the applicant has already demonstrated the effectiveness of the program credited, which is an acceptable basis for the exception.

The staff finds that the Diesel Fuel Monitoring Program adequately manages the loss of material for carbon steel components in a fuel oil environment. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 Quality Assurance for Aging Management of Nonsafety-Related Components

Section 3.0.4 of this SER provides the staff's evaluation of the applicant's Quality Assurance Program.

3.3.2.2.9 Crack Initiation and Growth Due to Stress-Corrosion Cracking and Cyclic Loading

In LRA Section 3.3.2.2.9, the applicant addressed further evaluation of programs to manage cracking in the CVCS to verify the effectiveness of the Water Chemistry Control Program.

Section 3.3.2.2.9 of the SRP-LR states that crack initiation and growth due to SCC and cyclic loading could occur in the channel head and access cover, tubesheet, tubes, shell and access cover, and closure bolting of the regenerative heat exchanger and in the channel head and access cover, tubesheet, and tubes of the letdown heat exchanger in the CVCS. The Water Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines of EPRI TR-105714, "PWR Primary Water Chemistry Guidelines: Revision 4," to manage the effects of crack initiation and growth due to SCC and cyclic loading. The applicant should verify the effectiveness of the chemistry control program to ensure that crack initiation and growth are not occurring. The GALL Report recommends further evaluation to manage crack initiation and growth from SCC and cyclic loading for these systems to verify the effectiveness of the Water Chemistry Control Program. A one-time inspection of selected components and susceptible locations is an acceptable method to ensure that crack initiation and growth are not occurring and that the component's intended function will be maintained during the period of extended operation.

The GALL Report recommends GALL AMP XI.M2 and a plant-specific verification program for management of this aging effect.

The GALL Report recommends that the Water Chemistry Control Program be augmented by verifying the absence of cracking due to SCC and cyclic loading, or the loss of material due to pitting and crevice corrosion. The GALL Report states that an acceptable verification program should include temperature and radioactivity monitoring of the shell-side water and eddy-current testing of tubes.

In the LRA, the applicant stated that it will manage this aging effect using its Water Chemistry Control—Closed-Cycle Cooling Water Chemistry Control Program (CNP AMP B.1.40.2), supplemented with the Heat Exchanger Monitoring Program (CNP AMP B.1.13). Sections 3.0.3.2.16 and 3.0.3.3.5 of this SER, respectively, document the staff evaluation of these programs. The applicant also used the Water Chemistry Control—Chemistry One-Time Inspection Program (CNP AMP B.1.41). Section 3.0.3.3.17 of this SER documents the staff's evaluation of the Chemistry One-Time Inspection Program.

The staff finds that the Heat Exchanger Monitoring Program provides an acceptable way to monitor the effectiveness of the Water Chemistry Control Program. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

In LRA Section 3.3.2.2.10, the applicant addressed the reduction of neutron-absorbing capacity and loss of material due to general corrosion, which could occur in the neutron-absorbing sheets of the spent fuel storage rack in the spent fuel storage.

Section 3.3.2.2.10 of the SRP-LR states that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of the spent fuel storage rack in the spent fuel storage. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant used the Boral Surveillance Program (CNP AMP B.1.3) and the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1) to manage neutron-absorbing capacity and loss of material. Sections 3.0.3.3.3 and 3.0.3.2.15 of this SER, respectively, document the staff's evaluation of these programs. The staff finds the use of the Boral Surveillance and Water Chemistry Control Programs acceptable for mitigating this aging effect. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.11 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

In LRA Section 3.3.2.2.11, the applicant addressed the potential for loss of material in buried piping of the service water and diesel fuel oil systems.

Section 3.3.2.2.11 of the SRP-LR states that the 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) and in the diesel fuel oil system. The Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of the loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the Buried Piping and Tanks Inspection Program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, thus ensuring that the loss of material is not occurring.

The GALL Report recommends AMP XI.M34 for management of this aging effect.

The applicant stated in the LRA that the CNP ESW system has no buried components. To manage the loss of material for buried components of the diesel fuel oil system, the applicant credited CNP AMP B.1.6, "Buried Piping Inspection," which the staff evaluates in Section 3.0.3.2.2 of this SER. The program calls for the opportunistic inspection of buried pipe when excavated. The staff reviewed the applicant's operating history and find that the frequency of pipe excavation is sufficient to allow the applicant to manage the effects of loss of material in this manner.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for the loss of material so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that the applicant has adequately addressed the issues that received further evaluation. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.4.2.2 of the SRP-LR. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3 AMR Results That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report

Summary of Technical Information in the Application

In Tables 3.3.2-1 through 3.3.2-11 of the LRA, the staff reviewed additional details of the results of the AMRs for material, environment, AERMs, and AMP combinations that are not consistent with the GALL Report.

In Tables 3.3.2-1 through 3.3.2-11, the applicant indicated, via notes F through J, that the GALL Report evaluates neither the identified component nor the material and environment combination. The applicant also provided information concerning how it will manage the AERMs.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that neither the identified component nor the material and environment combination is evaluated in the GALL Report.

<u>Staff Evaluation</u>

For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that it will adequately manage the effects of aging so that the intended function will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The following sections discuss the staff evaluation.

3.3.2.3.1 Spent Fuel Pool System

<u>Staff Evaluation</u>

The staff reviewed the AMR of the SFP system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-1. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-1 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component type evaluated in this section includes SFP poison.

For this component type, the applicant identified the following materials, environments, and AERMs:

- Aluminum exposed to an internal and external borated treated water environment is subject to cracking.

On the basis of its review of the information provided in the LRA, the staff finds that the aging effect of the above SFP system component type is consistent with industry experience for this combination of material and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above component in the SFP system.

Aging Management Programs

After evaluating the applicant's identification of the aging effect for the above component type, the staff evaluated the AMP to determine if it is appropriate for managing the identified aging effect. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-1 of the LRA identifies the CNP Water Chemistry Control Program as managing the aging effect described above for the SFP system. The staff's detailed review of this AMP appears in Section 3.0.3.3.16 of this SER. During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.1-1

The applicant's Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program (CNP B.1.40.3) (page B-128 of the LRA) states the program's purpose as managing the loss of material and fouling. The program description further states that it does not provide for the detection of aging effects, such as the loss of material and cracking. Table 3.3.2-1 of the LRA (page 3.3-32) identifies cracking as a SFP poison aging effect and the Water Chemistry Control Program as the applicable AMP. In RAI 3.3.2.1.1-1, the staff asked the applicant to identify the AMP used to manage cracking of SFP poison and provide justification that the program will ensure that the component's intended function is maintained during the period of extended operation.

By letter dated June 8, 2004, the applicant stated that the water in the SFP is included in the Primary and Secondary Water Chemistry Control Program (not the Auxiliary Systems Water Chemistry Control Program). In LRA Section B.1.40.1, the applicant identified the Primary and Secondary Water Chemistry Control Program as managing the cracking of components. Table 3.3.2-1 of the LRA (page 3.3-32) conservatively identifies cracking as an AERM since aluminum alloys are susceptible to cracking from stress corrosion and IGA in corrosive environments with high chloride concentrations. The Primary and Secondary Water Chemistry Program, which controls SFP water quality by maintaining chemistry levels (i.e., chlorides, fluorides, and sulfates) within acceptable limits, prevents this aging effect. Therefore, the Primary and Secondary Water Chemistry Control Program is adequate to manage this aging effect for aluminum, such that the boral will continue to maintain its component intended function through the period of extended operation. Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.1-1 acceptable because the response clarifies water chemistry control of the SFP and aging management of its related components susceptible to cracking; therefore, the staff's concerns described in RAI 3.3.2.1.1-1 are resolved.

On the basis of its review of the information provided in the LRA, the staff finds that the applicant has identified appropriate AMPs for managing the aging effect of the SFP system component type that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the SFP system components identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.2 Essential Service Water System

Staff Evaluation

The staff reviewed the AMR of the ESW system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-2. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-2 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component types evaluated in this section include bolting, detector wells, expansion joints, fittings, flex hose, manifold (piping), orifices, piping, thermowell, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Elastomer exposed to an external condensation environment is subject to change in material properties and cracking. Elastomer exposed to an internal raw water (fresh) environment is subject to change in material properties, cracking, and loss of material.

- For stainless steel and copper alloy exposed to external condensation, the applicant identified no AERMs.

Section 3.3.2.3.12 presents the staff's evaluation of the loss of preload and cracking for closure bolting.

On the basis of its review of the information in the LRA, the staff finds that the aging effects of the above ESW component types are consistent with industry experience for this combination of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above component in the ESW system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for the above components, the staff evaluated the AMP to determine if it is appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-2 of the LRA identifies the Service Water System Reliability Program for managing the aging effects described above for the ESW system. The staff's detailed review of this AMP appears in Section 3.0.3.2.11 of this SER. During its review, the staff determined that it needed additional information to complete its review.

RAI 3.3.2-2

The LRA states on page B-96 that the applicant will enhance the Service Water System Reliability Program (CNP B.1.29) to check for evidence of selective leaching during visual inspections. However, GALL Report AMP XI.M33 recommends a visual inspection and a hardness measurement of selected components to determine whether a loss of material due to selective leaching is occurring. In RAI 3.3.2-2, the staff asked the applicant to justify excluding a hardness measurement from the Service Water System Reliability Program to detect selective leaching.

By letter dated June 8, 2004, the applicant stated that since the detection of selective leaching is an enhancement to the Service Water System Reliability Program, specific details on the methods for the detection of selective leaching are not available at this time. Implicit in the current commitment to enhance the Service Water System Reliability Program is the implementation of industry best practices. Current industry practices include visual inspections and either hardness testing, as stated in GALL AMP XI.M33, or other inspection methods. Additionally, in the future, more effective techniques for the detection of selective leaching may become available. Based on its review, the staff finds the applicant's response to RAI 3.3.2-2 acceptable, because the applicant committed to enhance the Service Water System Reliability Program for the detection of selective leaching using industry best practices at the time of implementation. Therefore, the staff's concern described in RAI 3.3.2-2 is resolved. This is Commitment #21 in Appendix A of this SER.

For stainless steel exposed to external condensation, the applicant identified no AERMs. The component types affected are bolting, detector wells, fittings, flex hose, orifice, piping, thermowell, tubing, and valve. Because the applicant did not identify any AERMs, the staff finds that the absence of an AMP for stainless steel components exposed to condensation is acceptable.

For copper alloy manifold (piping), piping, tubing, and valves exposed to condensation, the applicant identified no AERM. No aging effects are considered to require management for copper components exposed to condensation. Because the applicant did not identify any AERMs, the staff finds that the absence of an AMP for copper components exposed to condensation is acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects for the ESW system components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.3 Component Cooling Water System

Staff Evaluation

The staff reviewed the AMR of the CCW system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-3. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.3-3 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component types evaluated in this section include bolting, detector well, fittings, heat exchangers, heat exchanger (shell), heat exchanger (tubes), manifold (piping), piping, thermowells, tubing, and valves.

For the heat exchanger tubes component type, the applicant identified the following materials, environments, and AERMs:

- Copper alloy exposed to an external treated water environment is subject to loss of material.

Section 3.3.2.3.12 of this SER contains the staff's evaluation of the loss of preload and cracking for closure bolting.

On the basis of its review of the information provided in the LRA, the staff finds that the aging effects of the component cooling water system component types are consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effect for the material and environment associated with the above component of the CCW system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for the above component types, the staff evaluated the AMP to determine if it is appropriate for managing the identified aging effect. The staff also verified that the UFSAR Supplement adequately describes the program.

LRA Table 3.3.2-3 identifies the following AMP for managing the aging effect described above for the heat exchanger tubes component type.

- Heat Exchanger Monitoring Program

The staff's detailed review of this AMP appears in Section 3.0.3.3.5 of this SER.

For stainless steel exposed to external condensation, the applicant identified no AERMs. The component types affected include bolting, detector well, fittings, heat exchanger, heat exchanger (shell), manifold (piping), piping, thermowell, tubing, and valves. Because the applicant did not identify any AERMs, the staff finds that the absence of an AMP for stainless steel components exposed to condensation is acceptable.

For copper alloy fittings, manifold, piping, tubing, and valves exposed to condensation, the applicant identified no aging effects that require management. Thus, the staff finds that the absence of an AMP for copper components exposed to condensation is acceptable.

In the LRA, the applicant stated that it will manage loss of material from copper alloy fittings, manifold, piping, tubing, and valves exposed to treated water by using the Closed Cooling Water Chemistry Control Program. On the basis of industry operating experience with copper alloy in a treated water environment, the staff finds this approach acceptable.

In the LRA, the applicant stated that it will manage loss of material for stainless steel exposed to treated water in the CCW system by using the Water Chemistry Control—Closed Cooling Water Chemistry Control program (CNP AMP B.1.40.2). This applies to detector well, fittings, heat exchanger tubes, manifold, piping, thermowell, tubing, and valve component types. The applicant stated that this program is consistent with GALL AMP XI.M21, with exceptions. Section 3.0.3.2.16 of this SER documents the staff's evaluation of this program.

The staff reviewed stainless steel components exposed to treated water and concludes that the effects of general, pitting, and crevice corrosion on stainless steel components are not significant in chemically treated water. For this reason and because the Water Chemistry Control Program is consistent with the GALL Report, the staff finds the applicant's approach acceptable.

In the LRA, the applicant stated that it will manage cracking of stainless steel exposed to treated water in the CCW system with closed cooling water chemistry control. This applies to fittings, manifold, piping, thermowell, tubing, and valve component types. The staff found that the GALL Report does not include this material and environment combination for CCW component types; however, it has been considered acceptable to manage the cracking of stainless steel using water chemistry control supplemented by inspection or monitoring programs. The staff asked the applicant to identify the program or programs that it will use to confirm the effectiveness of water chemistry control for managing this aging effect, or clarify the rationale for relying on water chemistry control alone. In the related RAI B.1.41-2, the staff asked the applicant to provide a list of components, material types, environments, and aging effects that it will inspect using the Water Chemistry Control—Chemistry One-Time Inspection Program (CNP AMP B.1.41) and to justify that the components selected constitute an adequate sample size to verify the effectiveness of the Water Chemistry Control Program for each aging effect to be managed. Section 3.0.3.3.17 of this SER provides the response to and staff evaluation of RAI B.1.41-2.

In the LRA, the applicant stated that it will manage the loss of material from stainless steel heat exchanger component types (including shell and tubes) by using the Oil Analysis Program (CNP AMP B.1.23). Section 3.0.3.3.8 of this SER documents the staff's evaluation of this program.

Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages the loss of material for components exposed to lubricating oil, including stainless steel.

On the basis of its review of the information provided in the LRA, the staff finds the applicant has identified the appropriate AMP for managing the aging effects of the component cooling water system component types addressed in this section. In addition, the staff finds the program descriptions in the UFSAR supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the CCW system components identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.4 Compressed Air System

Staff Evaluation

The staff reviewed the AMR of the CA system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-4. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs with managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.3-4 of the LRA lists individual system components that are within the scope of license renewal and are subject to AMR. The component types evaluated in this section include bolting, fittings, flex hoses, piping, tanks, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Stainless steel exposed to an internal treated air environment is subject to loss of material.

- Brass exposed to an internal environment of treated air is subject to loss of material.
- Elastomer exposed to an internal environment of treated air experiences change in material properties and cracking.
- Copper alloy exposed to an internal treated air environment is subject to loss of material.

Section 3.3.2.3.12 of this SER contains the staff's evaluation of the loss of preload and cracking for closure bolting.

On the basis of its review of the information provided in the LRA, the staff finds that the aging effects of the above CA system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the CA system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-4 of the LRA identifies the following AMPs for managing the aging effects described above for the CA system:

- Instrument Air Quality Program
- Preventive Maintenance Program

The staff's detailed reviews of these AMPs appear in Sections 3.0.3.3.7 and 3.0.3.3.10 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.4-1

Table 3.3.2-4, page 3.3-49, of the LRA identifies change in material properties and cracking as AERMs for elastomer flex hose components in an internal treated air environment. The applicant credited the Preventive Maintenance Program (CNP AMP B.1.25, page B-82 of the LRA) with managing these aging effects by periodic visual inspections and replacement as necessary. It is not apparent from the program description if the flex hoses will be inspected both internally and externally. The effectiveness of a visual inspection in detecting internal changes in material properties and cracking is also not apparent. Therefore, in RAI 3.3.2.1.4-1, the staff asked the applicant to justify that the Preventive Maintenance Program will adequately identify and manage the identified internal aging effects.

By letter dated June 8, 2004, the applicant stated that the elastomer flex hoses listed in LRA Table 3.3.2-4 are control air system rubber hoses located in containment. These hoses are exposed to treated air internally and ambient air externally. Degradation of rubber from cracking and change in material properties can result from ultraviolet radiation, ionizing radiation, or thermal exposure. The external and internal hose surfaces are exposed to the same environmental conditions, with the exceptions that the air environments differ and the internal hose surfaces are not exposed to ultraviolet radiation, since they are not exposed to light. Since the external surface is exposed to an environment that is more severe than the internal environment, the condition of the external surface would conservatively reflect the condition of the internal surface. Therefore, the applicant stated that inspection of the external surfaces is adequate to ensure detection of aging effects before loss of the pressure boundary intended function occurs.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.4-1 acceptable. The applicant's response clarifies the specific elastomer control air components requiring aging management, as well as the associated environmental conditions and preventive maintenance activities. The applicant's response indicates that external environmental conditions are more severe than the internal environmental conditions for the components of concern. Based on these environmental conditions, the response indicates that visual inspection of the external surface will successfully manage the associated aging of these elastomer components and that inspection of the internal surface is not necessary. Aging of elastomer components is a complex issue. The materials' specific chemical properties, as well as environmental conditions, affect the rate of aging. As the applicant's response indicates, internal and external environmental conditions are different, but the applicant's assumption that the material aging will occur more rapidly and be more apparent at the external surface has not been substantiated. A study by Sandia National Laboratory titled, "Prediction of Elastomer Lifetimes from Accelerated Thermal Aging Experiments," by Kenneth T. Gillen and Roger L. Clough, indicates that oxygen concentration, as well as pressure, affects oxidation of elastomers. The applicant's response to RAI 3.3.2.1.4-1 did not provide adequate information to justify aging management of these components by external visual observation only. The staff has asked the applicant to substantiate the adequacy of external surface visual examination in managing aging by providing details related to the applicable component's inspection/failure/repair frequency during the plant's operating history. In addition, CNP AMP B.1.25 does not provide an inspection frequency for the hoses such that the intended function will be maintained.

By letter dated October 18, 2004, the applicant stated that a review of the operating experience for these hoses did not identify any pressure boundary failures due to elastomer degradation. However, prior to the period of extended operation, I&M will inspect internal hose ends and external surfaces of the in-containment control air system rubber hoses referred to in LRA Table 3.3.2-4. The periodicity of future inspections will be based on the condition of the hoses in relation to their time in service. Based on its review, the staff finds the applicant's assessment of operating history and conditions for verification and future inspections acceptable for managing the aging effects to the hoses; therefore, the staff's concern described in RAI 3.3.2.1.4-1 is resolved.

For stainless steel exposed to ambient air, the applicant did not identify any AERMs. The component types affected are bolting, flex hose, piping, tubing, and valves. Because the applicant identified no AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

For brass fittings and valve component types exposed to ambient air (external) or nitrogen (internal), the applicant identified no AERMs. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for brass components exposed to ambient air or nitrogen to be acceptable.

In the LRA, the applicant stated that it will manage the cracking and change of material properties of elastomers of the flex hose component type in ambient air by using the Preventive Maintenance Program (CNP AMP B.1.25). The staff evaluation of this program appears in Section 3.0.3.3.10 of this SER. The staff only found documentation of visual inspection, which is an acceptable method for the detection of cracking. The staff asked the applicant to clarify the method(s) used to monitor a change in material properties of elastomers in the flex hose associated with the CA system. Material properties that could affect the performance of elastomers (e.g., hardness, flexibility) are not directly measured.

RAI 3.3.3-2

By letter dated August 20, 2004, in RAI 3.3.3-2, the staff asked the applicant to provide a basis for concluding that it will identify degradation of the elastomers before the intended function is compromised, or to provide a technical basis for the conclusion that the elastomers in question are not subject to these aging effects.

In its response dated September 2, 2004, the applicant stated that it will verify the flexibility of the hoses through physical manipulation of the hose during the visual inspection, thereby enhancing the inspector's ability to sense (both visually and through touch) a change in material properties that could affect the performance of the elastomers. The applicant stated that the Preventive Maintenance Program will use appropriate examination methods to ensure the identification of any degradation of flexible hoses in the CA system before the intended function is compromised.

On the basis of its review of the applicant's response to RAI 3.3.3-2, the staff finds that the applicant has demonstrated that it will adequately manage change in material properties resulting from the hardening and flexibility of flexible hoses in the CA system so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

For steel components exposed to nitrogen, the applicant identified no AERMs. The component types affected are carbon steel piping, tank, tubing, and valves, as well as stainless steel piping, tubing, and valves. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for steel components exposed to nitrogen to be acceptable.

In the LRA, the applicant stated that it will manage loss of material from carbon steel piping, tank tubing, and valve component types, when exposed to treated air, using CNP AMP B.1.19, "Instrument Air Quality." The staff evaluation of this program appears in Section 3.0.3.3.7 of this SER. Because plant operating experience demonstrates that the Instrument Air Quality Program is adequate to satisfy the requirements of GL 88-14, this approach is acceptable to the staff.

For copper alloy piping, tubing, and valves exposed to ambient air, the applicant identified no AERMs. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for copper alloy components exposed to ambient air to be acceptable.

For stainless steel exposed to nitrogen, the applicant identified no AERMs. The component types affected are piping, tubing, and valves. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to nitrogen to be acceptable.

On the basis of its review of the information provided in the LRA and supplemental information provided by the applicant, the staff finds the applicant has identified appropriate AMPs for managing the aging effects of the compressed air system component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects for the compressed air system components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.5 Chemical and Volume Control System

Staff Evaluation

The technical staff reviewed the AMR of the CVCS component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-5. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.3-5 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component types evaluated in this section include bolting, filter housing, flow element body, heat exchanger (bonnet), heat exchanger (shell), heat exchanger (tubes), heater housing, level glass gauge, manifold (piping), orifices, piping, piping-spool assembly, pulsation dampener, pump casing, strainer–tee, tanks, thermowell, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel exposed to an external air environment is subject to loss of material and loss of mechanical closure integrity. Carbon steel exposed to an internal treated water environment is subject to loss of material.

- Stainless steel exposed to an external treated (borated) water greater than 132 °C (270 °F) environment is subject to loss of material—wear, loss of material—erosion, and cracking-fatigue.

- Glass exposed to an internal environment of treated (borated) water experiences no aging effects.

Section 3.3.2.3.12 provides the staff's evaluation of loss of preload and cracking for closure bolting.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.5-1

Table 3.3.2-5 of the LRA (page 3.3.62) identifies the Boric Acid Corrosion Prevention Program (CNP AMP B.1.4) as managing the loss of material on the internal surface of a carbon steel tank in an air environment. The program description states that the applicant performs periodic visual inspections of components on which borated reactor water may leak. In RAI 3.3.2.1.5-1, the staff asked the applicant to explain how the visual inspection referred to in the Boric Acid Corrosion Prevention Program will adequately identify and manage the internal aging effects for the tank.

By letter dated June 8, 2004, the applicant stated the following:

> The tanks with carbon steel surfaces that are included in the component type "Tank" listed in the LRA Table 3.3.2-5 are the volume control and boric acid tanks. These tanks are primarily stainless steel, but the manway external cover and some external welded sub-components, such as the tank support legs, are carbon steel. The carbon steel manway cover has a stainless steel liner that protects the carbon steel from contact with borated water. As identified in LRA Table 3.3.2-5, the inside surface of the stainless steel liner is subject to an air (internal) and treated borated water (internal) environment, and will be included in the scope of the Water Chemistry Control Program. LRA Table 3.3.2-5 also correctly indicates that the external carbon steel tank sub-components (i.e., the manway cover and other welded sub components, such as the tank support legs) are subject to an air (external) environment, and are included in the scope of the Boric Acid Corrosion Prevention and System Walkdown Programs. The air (internal) environment on carbon steel is conservatively considered to be applicable to inside surface of the manway cover, which is protected from the treated borated water environment by the stainless steel liner. The Boric Acid Corrosion Prevention Program is applicable because the carbon steel

> subcomponents are in an air environment with the potential for exposure to borated water leakage.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.5-1 acceptable. The applicant's response clarifies the tank design in relationship to the carbon steel internal components referenced in LRA Table 3.3.2-5, page 3.3.62. From this new information provided by the applicant, the staff cannot determine how the Boric Acid Corrosion Prevention Program will detect the loss of liner integrity and subsequent degradation of the carbon steel manway. The applicant should explain how the visual inspection referred to in the Boric Acid Corrosion Prevention Program will identify the loss of tank manway cover liner integrity and subsequent degradation of the carbon steel internal surface. The staff's concern focuses on the following part of the applicant's response:

> The air (internal) environment on carbon steel is conservatively considered to be applicable to inside surface of the manway cover, which is protected from the treated borated water environment by the stainless steel liner. The Boric Acid Corrosion Prevention Program is applicable because the carbon steel subcomponents are in an air environment with the potential for exposure to borated water leakage.

The staff interprets this to indicate that the applicant has conservatively included the carbon steel material that is lined with stainless steel (manway cover) to possibly address aging from the leakage of boron, should the liner fail. Further, the applicant apparently took credit for the Boric Acid Corrosion Prevention Program to manage this aging effect. If this interpretation is correct, it is unclear how an external inspection of the manway will detect the loss of the stainless steel liner integrity and the resulting carbon steel degradation.

During the September 1, 2004 meeting, the applicant showed a diagram of the manway cover. It is a carbon steel blind flange located on the external side on a tank. The surface of the blind flange internal to the tank is lined with stainless steel. The applicant explained that the Boric Acid Corrosion Prevention Program would be used to detect degradation on the external carbon steel portion of the flange only. The Boric Acid Corrosion Prevention Program does not address the internal portion of the flange. The applicant stated that the Water Chemistry Control Program is used to detect the loss of the internal stainless steel liner integrity. The staff finds the applicant's clarification of this issue provided during the meeting and documented in the meeting minutes to be adequate . Based on its review, the staff finds the applicant's explanation of the flange configuration and applicability of appropriate AMPs acceptable to resolve all questions staff has associated with RAI 3.3.2.1.5-1. Therefore, the staff's concern described in RAI 3.3.2.1.5-1 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 the above RAI, the staff finds that the aging effects of the above chemical and volume control system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above component types in the CVCS.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-5 of the LRA identifies the following AMPs for managing the aging effects described above for the CVCS:

- Boric Acid Corrosion Prevention Program
- System Walkdown Program
- TLAA—Metal Fatigue Program
- Heat Exchanger Monitoring Program
- System Testing Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.14, 4.3, 3.0.3.3.5, and 3.0.3.3.13 of this SER, respectively.

In the LRA, the applicant identified no aging effect for stainless steel bolting, filter housing, flow element body, heat exchanger (bonnet), heat exchanger (shell), heater housing, manifold (piping), orifice, piping, piping-spool assembly, pulsation damper, pump casing, strainer (tee), tank, thermowell, tubing, and valve component types exposed to air. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage loss of material for stainless steel in treated, borated water using its Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1). This applies to the filter housing, flow element body, heat exchanger (bonnet, shell, and tubes), heater housing, manifold (piping), orifice, piping, piping spool assembly, pulsation dampener, pump casing, strainer-tee, tank, thermowell, tubing, and valve component types in the CVCS. Section 3.0.3.2.15 of this SER documents the staff's evaluation of this program.

The GALL Report does not identify this material and environment combination for this system. Because stainless steel components are not subject to significant general, pitting, and crevice corrosion in treated, borated water, the staff finds this approach acceptable.

In the LRA, the applicant stated that it will use the Water Chemistry Control Program to manage fouling of stainless steel heat exchanger tubes in treated, borated water. The GALL Report does not identify this aging effect for this component, material, and environment combination. The staff finds the use of the Water Chemistry Control Program to be acceptable.

In the LRA, the applicant stated that it will use the Water Chemistry Control Program to manage cracking of stainless steel in treated, borated water. This affects orifice, piping, thermowell, tubing, and valve component types in the CVCS. On the basis that this approach is similar to the management of cracking of stainless steel in this environment in other non-Class 1 systems, the staff finds the use of the Water Chemistry Control Program to be acceptable for these components.

In the LRA, the applicant stated that it identified no aging effects for stainless steel piping and valves exposed to an environment of hydrogen or nitrogen gas. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to a hydrogen or nitrogen gas environment to be acceptable.

In the LRA, the applicant stated that there are no aging effects for the level glass gauge component type (glass) in an internal environment of treated (borated) water. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that these components have no AERMs, the staff finds the absence of an AMP for glass 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 applicant has identified appropriate AMPs for managing the aging effects of the CVCS component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the CVCS components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.6 Heating, Ventilation, and Air Conditioning Systems

Staff Evaluation

The staff reviewed the AMR of the heating, ventilation, and air conditioning (HVAC) system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-6. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-6 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component types evaluated in this section include bolting, dryer, heat exchanger (shell), heat exchanger (tubes), heater housing, piping, sight glass, sight glass housing, tanks, test canister housing, thermowells, tubing, valves, and ventilation unit housing.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel exposed to an internal air environment is subject to loss of material.
- Stainless steel exposed to an external condensation environment is subject to fouling, loss of material, and loss of material—wear.
- Copper alloy exposed to an external condensation environment is subject to loss of material or loss of material—wear.
- Copper alloy exposed to an external environment of Freon experiences loss of material—wear. Copper alloy exposed to an external environment of condensation experiences the aging effect of fouling.
- Copper alloy exposed to an external environment of raw water (fresh) or treated water experiences the aging effects loss of material and loss of material—wear.
- Glass exposed to condensation, Freon, or treated water environments experiences no aging effects.

Section 3.3.2.3.12 provides the staff's evaluation of the loss of preload and cracking for closure bolting.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2-1

In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, the applicant listed several components having environments and applicable aging effects with associated AMPs. In the same columns, for the same component, material, and environment, the applicant listed no aging effects and no AMPs. For example, Table 3.3.2-11, page 3.3-130, identifies stainless steel bolting with a function of pressure boundary exposed to an external environment of air as experiencing loss of material managed by the Bolting and Torquing Activities Program. The same item in the table on page 3.3-130 for the same component exposed to the same environment has no aging effects and therefore no AMP. In addition, Table 3.3.2-6, page 3.3-77, shows that copper alloy valves exposed to an external condensation environment experience loss of material. The same item in the table on page 3.3-77 for the same component exposed to the same environment has no aging effects and therefore no AMP. In RAI 3.3.2-1, the staff asked the applicant to explain these contradictory entries in the LRA tables.

By letter dated June 8, 2004, the applicant provided the following response applicable to the HVAC system for RAI 3.3.2-1:

> In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, there are six instances in which a component type lists both an aging effect and "none" for the same material/environment combination. While this appears contradictory where

occurring, it is not because each component type in the table actually represents more than one component in the system. While the components are exposed to the same overall environment, specific conditions for individual components differ. The following paragraphs provide additional information for the instances applicable to the heating, ventilation, and air conditioning system:

•LRA Table 3.3.2 6, Heating, Ventilation, And Air Conditioning Systems (Page 3.3-77)—copper alloy valves exposed to external condensation
Copper alloy valves associated with the auxiliary feed pump room ventilation may be wetted by condensation that could contain sulfates, chlorides, or fluorides. Therefore, loss of material was identified as an aging effect requiring management for these copper alloy valves exposed to condensation. Copper alloy valves within the control room liquid chiller packages may be wetted by condensation. However, since these components are in a clean, air-conditioned environment, the condensation should not contain sulfates, chlorides, or fluorides. Therefore, no aging effects requiring management were identified for these copper alloy valves exposed to condensation.

The staff finds the applicant's response to RAI 3.3.2-1 acceptable because each component type in the table actually represents more than one component in the system, and while the components are exposed to the same overall environment, specific conditions for individual components differ as discussed by the applicant; therefore, the staff's concerns described in RAI 3.3.2-1 are 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 RAI 3.3.2-1, the staff finds that the aging effects of the above HVAC system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the HVAC system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-6 of the LRA identifies the following AMPs for managing the aging effects described above for the HVAC system:

- Preventive Maintenance Program
- Heat Exchanger Monitoring Program
- Service Water System Reliability Program
- Water Chemistry Control Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.3.10, 3.0.3.3.5, 3.0.3.2.11, and 3.0.3.3.16 of this SER, respectively.

For stainless steel components exposed to air (external or internal surface), condensation (external surface), or outdoor air (external surface), the applicant identified no aging effects. Component types addressed include bolting, piping, sight glass housing, tank, thermowell, valves, and the ventilation unit housing. The staff finds this acceptable.

Because the applicant did not identify any AERMs, the staff finds the absence of an AMP for stainless steel components exposed to condensation to be acceptable.

The applicant identified no aging effects for copper-alloy component types exposed to Freon, including the dryer, heat exchanger tubes, piping, sight glass housing, tubing, and valves. Because the applicant did not identify any AERMs for these components, the staff finds the absence of an AMP for copper-alloy components exposed to Freon to be acceptable.

In the LRA, the applicant stated that it will use its Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program (CNP AMP B.1.40.3) to manage the fouling of copper alloy and stainless steel heat exchanger tubes in treated water. This applies to the heat exchanger (tubes) component type in the HVAC systems. The staff documents its evaluation of this program in Section 3.0.3.3.16 of this SER.

In the LRA, the applicant stated that it will use its Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program (CNP AMP B.1.40.3) to manage the loss of material for stainless steel in treated water. This applies to the heat exchanger (tubes), piping, sight glass housing, tank, thermowell, and valve component types in the HVAC systems. The staff documents its evaluation of this program in Section 3.0.3.3.16 of this SER.

For copper-alloy components exposed to air, including the heater housing, piping, sight glass housing, test canister housing, and valves, the applicant identified no aging effects that require aging management. Because the applicant did not identify any AERMs, the staff finds the absence of an AMP for copper components exposed to condensation to be acceptable.

In the CNP LRA, the applicant identified no aging effects for copper alloy piping and valve component types exposed to condensate. For the valve component type, the applicant did identify loss of material as an AERM for copper alloy material exposed to condensate. The staff asked the applicant to clarify the inconsistency between identical material and environment combinations.

By letter dated June 8, 2004, in response to the related RAI 3.3.2-1, the applicant stated that copper alloy valves associated with the auxiliary feed pump ventilation may be wetted by condensation that could contain sulfates, chlorides, or fluorides. In those cases, the applicant identified loss of material as an AERM. In other cases, the applicant stated that copper alloy valves within the control room liquid chiller packages may be wetted by condensation that does not contain sulfates, chlorides, or fluorides, and these specific valves do not have an AERM.

On the basis of its review of the response to RAI 3.3.2-1, the staff finds the issue resolved because the applicant appropriately identified and distinguished between the AERMs for the condensate environment containing sulfates, chlorides, or fluorides and the condensate environment not containing those constituents.

In the LRA, the applicant stated that it will manage loss of material from a carbon steel valve exposed to air internally through the System Walkdown Program (CNP AMP B.1.38). The staff documents its evaluation of this program in Section 3.0.3.3.14 of this SER.

In the related RAI 3.3.2.1.11-3, by letter dated May 26, 2004, the staff asked the applicant to explain how the System Walkdown Program will detect the loss of material on the internal surfaces of the several components. Section 3.3.2.3.11 of this SER provides the response to and staff evaluation of RAI 3.3.2.1.11-3.

In the LRA, the applicant stated that there are no aging effects for the sight glass component type (glass) in an external environment of condensation, or an internal environment of Freon or treated water. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that these components have no AERMs, the staff finds the absence of an AMP for glass to be acceptable.

On the basis of its review of the information provided in the LRA and the above RAI responses, the staff finds the applicant has identified appropriate AMPs for managing the aging effects of the HVAC system component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects for the HVAC system components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.7 Fire Protection System

Summary of Technical Information in the Application

In Section 3.3.2.1.7 of the LRA, the applicant identified the materials, environments, AERMs and AMPs for the FP system components.

In Table 3.3.2-7 of the LRA, the applicant provided a summary of AMRs for the FP system components and identified which AMRs it considered to be not consistent with the GALL Report.

Staff Evaluation

The staff reviewed LRA Section 3.3.2.1.7; LRA Table 3.3.1 Items 18 through 22 and Item 30; and Table 3.3.2-7 to determine whether the applicant demonstrated that it will adequately manage the effects of aging for the FP system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff conducted its review, described below, in accordance with Section 3.3 of the SRP-LR and the GALL Report.

Aging Effects

In reviewing LRA Section 3.3, the staff identified areas in which it needed additional information to complete its review. Therefore, by letter to the applicant dated March 3, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had demonstrated that it will adequately manage the effects of aging for the FP system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The following paragraphs describe the staff's RAIs and the applicant's responses.

RAI 3.3.1-1

In RAI 3.3.1-1(1), the staff inquiry concerned LRA Table 3.3.1, "Auxiliary Systems," item 3.3.1-18. The staff asked the applicant to verify that all FP underground piping and fittings are included in this item and have an AMP consistent with the GALL Report.

In its response, dated June 30, 2004, the applicant stated that this item does not include underground fire water system piping and fittings. The applicant provided AMR results for the fire water system, including the extent of consistency with the GALL Report, in LRA Table 3.3.2-7. Table 3.3.2-7 of the LRA indicates components that are compared with the items of LRA Table 3.3.1 by an entry in the "Table 1 Item" column. The applicant will manage the loss of material in buried fire water system piping and components through the Fire Water System Program, which, with enhancements, will be consistent with, but include exceptions to GALL AMP XI.M27.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-1(1) acceptable because, although the cited item does not include underground FP piping and fittings, the applicant showed that another item includes them in their entirety.

In RAI 3.3.1-1(2), the staff requested further explanation of LRA Table 3.3.1, item 3.3.1-19. The staff asked the applicant to verify if this item includes any dry sprinkler systems and to provide an AMP consistent with the GALL Report.

In its response, dated June 30, 2004, the applicant stated that it did not include dry sprinkler systems in this item. The applicant provided AMR results for the FP system, including the extent of consistency with the GALL Report, in LRA Table 3.3.2-7. An entry in the "Table 1 Item" column of LRA Table 3.3.2-7 indicates components included in Table 3.3.1. Item 3.3.1-5 of LRA Table 3.3.1 includes fire water piping with an internal air environment (i.e., dry sprinkler piping). The applicant will manage loss of material in dry sprinkler piping and components through the Fire Water System Program, which, with enhancements, will be consistent with, but include exceptions to GALL AMP XI.M27. (The applicant discussed the Fire Water System Program enhancements and exceptions to GALL AMP XI.M27 in LRA Section B.1.11.2.) In LRA Table 3.3.2-7, aluminum and copper alloy dry pipe sprinkler heads identified as component type "spray nozzles" that are exposed to air internally and externally have no aging effects because of the inherent corrosion resistance of these materials in air.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-1(2) acceptable because the applicant verified that it did not include dry sprinkler heads within the cited item.

In RAI 3.3.1-1(3), the staff requested further analysis of LRA Table 3.3.1, item 3.3.1-21. The staff notified the applicant that GALL AMP XI.M27 does not omit review of aging effects for treated water systems. Many of the aging effects/mechanisms listed are likely to occur even if raw water is not the primary source. The staff asked the applicant to clarify the discussion points for this item.

In its response, dated June 30, 2004, the applicant stated that item 3.3.1-21 of LRA Table 3.3.1 compares the alignment of the CNP AMR results with those in Table 3 (page 23) of the GALL Report. These items refer to items VII.G.6a and VII.G.6b in the GALL Report (page VII.G.5), which apply to water-based FP system components containing raw water. The CNP fire water system uses treated water rather than raw water. Although item 3.3.1-21 in LRA Table 3.3.1 does not apply to CNP, fire water system components with an internal treated water environment are subject to an AMR. Table 3.3.2-7 of the LRA lists aging effects and applicable AMPs for the fire water system components requiring aging management.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-1(3) acceptable because further evaluation shows that GALL AMP XI.M27 is specific for raw water. Table 3.3.2-7 of the LRA contains the components of concern for treated water throughout.

In RAI 3.3.1-1(4), the staff requested further explanation of LRA Table 3.3.2-7, "Fire Protection Systems—General." Notes F, G, H, I, J, and 3 all dictate that the GALL Report does not cover a portion of the item, but the applicant proposed no means of aging management evaluation. The staff asked the applicant to describe the intended AMP.

In its response, dated June 30, 2004, the applicant stated that as described in item 9 on LRA page 3.0-5, the notes in Table 3.3.2-7 describe the degree of consistency with the line items in the GALL Report and do not exclude components from AMR. The "Aging Management Programs" column of Table 3.3.2-7 identifies the aging effects of individual components and the associated AMPs.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-1(4) acceptable because, although the note refers to a specific variant of the component, the note is not intended to exclude the component from the AMP identified.

In RAI 3.3.1-1(5), the staff requested further analysis of LRA Table 3.3.2-7. The applicant did not specifically list hose valve stations under any item in the summary of aging management. The staff asked the applicant to identify an item which covers all hose valve stations and verify compliance with GALL AMP XI.M27.

In its response, dated June 30, 2004, the applicant stated that as indicated on license renewal drawings LRA-1-5152B and LRA-2-5152C, hose valve stations comprise valves, piping, and fittings. The component types "fittings," "piping," and "valve" identified in LRA Table 3.3.2-7 include the components of hose valve stations subject to an AMR. The Fire Protection Program manages aging effects associated with the treated water internal environment for the component types "fittings," "piping," and "valve" identified in LRA Table 3.3.2-7. As described in LRA Section B.1.11.2, the Fire Water System Program, with enhancements, will be consistent with but include exceptions to GALL AMP XI.M27. Section B.1.11.2 of the LRA describes and justifies those exceptions.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-1(5) acceptable because the applicant explained that the considered items include hose valve stations, designated by the separate parts of the valve.

RAI 3.3.1-2

In RAI 3.3.1-2(1), the staff requested more information about LRA drawings LRA-1-5151A, LRA-2-5151A, LRA-1-5151C, and LRA-2-5151C. At location L-5, a 1.5-inch vent line is present from the diesel fuel oil day tank through a flame arrester to the room. These drawings do not show the vent line and the flame arrester as subject to an AMR. However, it appears that the intended function of the flame arrester is to ensure that vented gas will not lead to a fire. This intended function is in accordance with 10 CFR 54.4(a)(3). The staff asked the applicant to justify the exclusion of the flame arrester and vent line from the scope of license renewal and from an AMR in accordance with the requirements of 10 CFR 54.4(a)(3) and 10 CFR 54.21(a)(1).

In its response, dated June 30, 2004, the applicant stated that the flame arrester was conservatively installed on the diesel fuel oil tank vent line but has no required intended function. It is not required to support operation of the diesel engines and performs no function that demonstrates compliance with the Commission's regulations for FP or other regulated events. The flashpoint for diesel fuel is sufficiently high that NFPA Standard 30 does not require a flame arrester, nor does the flame arrester have any function under 10 CFR 50.48.

Based on its review, the staff finds the applicant's response to RAI 3.3.1-2(1) acceptable because the flame arrester is a nonrequired element providing additional safety.

In RAI 3.3.1-2(2), the staff requested more information about LRA drawing LRA-1-5151A, LRA-2-5151A, LRA-1-5151C, and LRA-2-5151C. The drawings show a 2-inch overflow line at location L6 as excluded from an AMR. The staff asked the applicant to justify the exclusion of this overflow line from within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(3) and 10 CFR 54.21(a)(1).

In its response, dated June 30, 2004, the applicant stated that the overflow line directs fuel oil to a sump if the tank is overfilled. The vent line, flame arrester, and overflow line on the diesel fuel oil day tank are not safety related and do not perform a pressure boundary function since they are located above the fuel oil level in the tank and their failure would have no impact on the ability of an EDG to perform its intended functions. Therefore, the vent line, flame arrester, and overflow line on the diesel fuel oil day tanks do not have a license renewal intended function and are not subject to an AMR based on the criteria of 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3).

Based on its review, the staff finds the applicant's response to RAI 3.3.1-2(2) acceptable because the overflow line does not have a license renewal intended function.

Aging Management Programs

The staff reviewed Table 3.3.2-7 of the LRA, which summarized the results of AMR evaluations in the SRP-LR for the FP system component groups.

For stainless steel exposed to air, the applicant identified no AERMs. The component types affected are bolting (ambient air) and flex hose (ambient and internal). Because the applicant did not identify an AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

For copper alloy fittings, piping, spray nozzles, tubing, and valve component types exposed to ambient air, as well as filter housing, fittings, spray nozzles, and valve component types internally exposed to air, the applicant identified no aging effect. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for copper alloy components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it manages the loss of material from carbon steel FP components exposed to treated water using the Fire Protection Program (CNP.AMP B.1.11). Sections 3.0.3.2.5 and 3.0.3.2.6 of this SER, respectively, document the staff evaluation of this program. The program addresses fittings, flange, heat exchanger bonnet and shell, heater housing, orifice, piping, pump casing, spray nozzles, tank, and tubing component types. This is acceptable to the staff.

In the LRA, the applicant stated that loss of material from copper-alloy fittings, piping, tubing, and valve component types is managed using the Diesel Fuel Monitoring Program (CNP AMP B.1.10). The staff documents its evaluation of this program in Section 3.0.3.2.4 of this SER. On the basis that the Diesel Fuel Program maintains oil systems free of contaminants (primarily water and particles) and provides additives to mitigate aging effects, the staff finds that this program adequately manages fouling and the loss of material for components exposed to fuel oil.

In the LRA, the applicant stated that it manages the loss of material from copper alloy FP components exposed to treated water using the Fire Protection Program (CNP AMP B.1.11), which is subdivided into the Fire Protection (CNP AMP B.1.11.1) and Fire Water System (CNP AMP B.1.11.2) Programs. The staff documents its evaluation of the Fire Protection Program in Sections 3.0.3.2.5 and 3.0.3.2.6 of this SER, respectively. The program addresses fittings, heat exchanger tubes, spray nozzles, tubing, and valve component types. On the basis that the program includes the SCs that credit this plant-specific program, the staff finds this to be acceptable.

In the LRA, the applicant stated that it manages the loss of material from cast iron heat exchanger shell, copper alloy heat exchanger tubes, carbon steel piping, and pump casing component types exposed to lubricating oil using the Oil Analysis Program (CNP AMP.1.23). The staff evaluation of this program is documented in Section 3.0.3.3.8 of this SER. On the basis that the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages fouling and the loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that it manages the loss of material due to wear of copper-alloy heat exchanger tubes exposed to both lube oil and treated water using the Fire Protection Program. On the basis that the program includes the SCs that credit this plant-specific program, the staff finds this to be acceptable.

In the LRA, the applicant stated that it manages the loss of material from a carbon steel spray nozzle exposed to air internally using the System Walkdown Program (CNP AMP B.1.38). The staff evaluation of this program is documented in Section 3.0.3.3.14 of this SER. During the AMP audit at the applicant's offices, the staff asked how internal loss of material would be detected. The applicant's technical staff explained that loss of carbon steel material sufficient to challenge the intended function of the spray nozzle would be expected to produce indications that would be evident on inspection without disassembly. This is acceptable to the staff on the basis that (1) this plant-specific program provides for the management of loss of material for this component, (2) evidence of significant internal loss of material will be visible to those conducting system walkdowns, and (3) those conducting the walkdowns are guided by training and procedure to monitor this aging effect.

Conclusion

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 FP system components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.8 Emergency Diesel Generator

Staff Evaluation

The staff reviewed the AMR of the EDG system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-8. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects

Table 2.3.3-8 of the LRA lists individual system components that are within the scope of license renewal and are subject to an AMR. The component types evaluated in this section include bolting, compressor, expansion joints, filter housing, fittings, flex hoses, heat exchanger (shell), heat exchanger (tubes), heater housing, level glass gauge, manifold (piping), orifices, piping, pneumatic cylinder, pump casing, sight flow indicator, strainers, tanks, thermowells, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel exposed to an internal air environment is subject to loss of material and loss of material—wear. Carbon steel exposed to an internal exhaust air environment is subject to cracking-fatigue. Carbon steel exposed to an internal lube oil or treated water is subject to loss of material. Carbon steel bolts exposed to external air are subject to loss of mechanical closure integrity.

- Stainless steel exposed to an internal treated water environment is subject to cracking. Stainless steel bolts exposed to external air are subject to loss of mechanical closure integrity.

- Copper alloy exposed to an external air or lube oil environment is subject to fouling. Copper alloy exposed to an internal treated water environment is subject to fouling. Copper alloy exposed to a lube oil, external air, or treated water environment is subject to loss of material—wear.

- Glass exposed to air or treated water experiences no aging effects.

Section 3.3.2.3.12 of this SER contains the staff's evaluation of loss of preload and cracking for closure bolting.

During its review, the staff determined that it needed additional information to complete its evaluation.

In Tables 3.3.2-1 through Table 3.3.2-11 for the auxiliary systems, the applicant listed several components having environments and applicable aging effects with associated AMPs. In the same columns, for the same component, material, and environment, the applicant listed no aging effects and no AMPs. For example, in Table 3.3.2-11, page 3.3-130, the applicant identified stainless steel bolting with a function of pressure boundary exposed to an external environment of air as experiencing the loss of material, which is managed by the Bolting and Torquing Activities Program. The same item in the table on page 3.3-130 for the same component exposed to the same environment has no identified aging effects and therefore requires no AMP. In addition, in Table 3.3.2-6, page 3.3-77, copper alloy valves exposed to an external condensation environment experience the loss of material. The same item in the table on page 3.3-77 for the same component exposed to the same environment has no identified aging effects and therefore requires no AMP.

RAI 3.3.2-1

In RAI 3.3.2-1, the staff asked the applicant to explain these contradictory entries in the LRA tables. By letter dated June 8, 2004, the applicant provided the following response applicable to the EDG for RAI 3.3.2-1:

> In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, there are six instances in which a component type lists both an aging effect and "none" for the same material/environment combination. While this appears contradictory where occurring, it is not because each component type in the table actually represents

more than one component in the system. While the components are exposed to the same overall environment, specific conditions for individual components differ. The following paragraphs provide additional information for the instances applicable to the EDG:

- LRA Table 3.3.2-8, Emergency Diesel Generator (Page 3.3-95) - stainless steel bolting exposed to air externally

  Stainless steel bolting in this system is exposed to air and to significant vibration and/or elevated temperatures from the diesel engines. Therefore, loss of mechanical integrity (loss of pre-load) was identified as an aging effect requiring management for this stainless steel bolting exposed to air. Stainless steel bolting in parts of the emergency diesel generator system that are isolated from diesel engine vibration (e.g., air start subsystem) is exposed to air, but is not exposed to significant vibration or elevated temperatures from a diesel engine. Therefore, no aging effects requiring management were identified for this stainless steel bolting exposed to air.

Based on its review, the staff finds the applicant's response to RAI 3.3.2-1 acceptable because each component type in the table actually represents more than one component in the system, and while the components are exposed to the same overall environment, specific conditions for individual components differ as discussed by the applicant. Therefore, the staff's concerns described in RAI 3.3.2-1 are 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 RAI, the staff finds that the aging effects of the above EDG system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the EDG system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-8 of the LRA identifies the following AMPs for managing the aging effects described above for the EDG system:

- Bolting and Torquing Activities Program
- Preventive Maintenance Program
- TLAA—Metal Fatigue Program
- Oil Analysis Program
- Water Chemistry Control Program
- Heat Exchanger Monitoring Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.3.2, 3.0.3.3.10, 4.3, 3.0.3.3.8, 3.0.3.3.16, and 3.0.3.3.5 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

For several stainless steel components listed in LRA Table 3.3.2-8, pages 3.3-95 to 3.3-112, the applicant identified cracking as an AERM for stainless steel with an internal treated water environment. The applicant credited the Preventive Maintenance Program (CNP AMP B.1.25), on page B-82 of the LRA, with managing the cracking aging effect by general inspections rather than specific component-by-component listings. The program description states that the AMP will manage the loss of material, cracking, fouling, and change in material properties for EDG subsystem components. The GALL Report recommends management of these aging effects using chemistry control programs supplemented by one-time inspections in low-flow areas.

RAI 3.3.2.1.8-1

In RAI 3.3.2.1.8-1, the staff asked the applicant to justify the effectiveness of the Preventive Maintenance Program in managing the aging effect of cracking for each stainless steel component so identified in Table 3.3.2-8 or to revise Table 3.3.2-8 to include an applicable chemistry control program and one-time inspection.

By letter dated June 8, 2004, the applicant stated the following:

> Both the Preventive Maintenance Program, B.1.25, and the Chemistry One-Time Inspection Program, B.1.41, would be effective in managing the aging effect of cracking for stainless steel components subject to an internal treated water environment. The Preventive Maintenance Program is credited for managing cracking of stainless steel components containing treated water, because a representative sample of these components is inspected on a routine basis. These inspections would reveal evidence of cracking such that corrective actions can be taken to manage applicable aging effects. Degraded conditions or adverse trends identified during inspections are addressed through the corrective action process. In addition, the treated water environment of the EDG subsystems is included in the Auxiliary Systems Water Chemistry Control Program. Verification of the effectiveness of the chemistry control programs, by the Chemistry One-Time Inspection Program, will provide additional assurance that aging effects, such as cracking, are effectively managed.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.8-1 acceptable, because the applicant's response clarifies that it will use the appropriate AMPs recommended by the GALL Report to detect and manage cracking in the stainless steel components. The response resolves the initial concerns related to using the single AMP, the Preventive Maintenance Program, as cited in Table 3.2.2-8. Therefore, the staff's concerns described in RAI 3.3.2.1.8-1 are resolved.

RAI 3.3.2.1.8-2

Table 3.3.2-8 of the LRA (pages 3.3-95 to 3.3-112) identifies several carbon steel components in a treated water environment using a water chemistry control program to manage a loss of material aging effect. The GALL Report also supports using a water chemistry program for managing the loss of material to carbon steel. In RAI 3.3.2.1.8-2, the staff asked the applicant to justify not including an AMP to manage the water chemistry of the treated water environment for the carbon steel sight flow indicator (Table 3.3.2-8, page 3.3-106).

By letter dated June 8, 2004, the applicant stated that, consistent with other carbon steel components containing treated water as identified in LRA Table 3.3.2-8, the Water Chemistry Control Program manages the loss of material of the carbon steel sight flow indicator. The applicant inadvertently omitted the Water Chemistry Control Program from the component type "sight flow indicator," in LRA Table 3.3.2-8. Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.8-2 acceptable, because the applicant has provided an acceptable explanation (clerical error), as requested; therefore, the staff's concern described in RAI 3.3.2.1.8-2 is resolved.

For stainless steel exposed to air, the applicant identified no AERMs. The component types exposed to ambient air are bolting, fittings, flex hose, piping, strainer, thermowell, tubing, and valves, and those exposed to air internally are fittings, flex hose, piping, strainer, tubing, and valves. Because the applicant did not identify an AERMs, and this is consistent with industry experience, the staff finds the absence of a program for stainless steel components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will use the Oil Analysis Program (CNP AMP B.1.23) to manage the loss of material from carbon steel filter housing, fittings, heat exchanger shell, heater housing, piping, pump casing, strainer, tank, and valve. The staff evaluation of this program appears in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages loss of material for components exposed to lubricating oil.

For copper alloy filter housings, fittings, manifold, pneumatic cylinder, tubing, and valve component types exposed to ambient or internal air, the applicant identified no aging effects. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of a program for copper alloy components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will use the Water Chemistry Control Program (CNP AMP B.1.40) to manage the loss of material from carbon steel fittings, heat exchanger shell, heater housing, manifold, orifice, piping, pump casing, strainer, tank, thermowell, and tubing component types in treated water. The staff evaluation of this program appears in Sections 3.0.3.2.15, 3.0.3.2.16, and 3.0.3.3.16 of this SER. Because this approach is consistent with the management of similar items identified in the GALL Report, the staff finds it to be acceptable.

In the LRA, the applicant stated that it will manage the loss of material from carbon steel valve component types by using both the Water Chemistry Control Program and the plant-specific Preventive Maintenance Program (CNP AMP B.1.25). The staff evaluation of this program appears in Section 3.0.3.3.10 of this SER. Because the use of the Water Chemistry Control

Program is consistent with the management of similar items identified in the GALL Report, the staff finds that its use to supplement the Preventive Maintenance Program is acceptable.

In the LRA, the applicant stated that it will manage the loss of material from copper-alloy fittings, manifold, tubing, and valve component types by using the Diesel Fuel Monitoring Program (CNP AMP B.1.10). The staff evaluation of this program appears in Section 3.0.3.2.4 of this SER. Because the Diesel Fuel Monitoring Program maintains oil systems free of contaminants (primarily water and particles) and provides additives to mitigate aging effects, the staff finds that this program adequately manages fouling and the loss of material for components exposed to fuel oil.

In the LRA, the applicant stated that it will manage loss of material from copper alloy fittings, heat exchanger tubes, tubing, and valve component types exposed to lube oil by using the Oil Analysis Program (CNP AMP B.1.23). The staff evaluation of this program appears in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages cracking and the loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that it will manage the loss of material from copper alloy fittings and heat exchanger tubes in raw water by using the Service Water System Reliability Program (CNP AMP B.1.29). The applicant will also use this program to manage fouling of heat exchanger tubes. The staff evaluation of the Service Water System Reliability Program appears in Section 3.0.3.2.11 of this SER. Because the use of this program is consistent with the management of similar items identified in the GALL Report, the staff finds that its use to supplement the Preventive Maintenance Program is acceptable.

In the LRA, the applicant stated that it will manage the loss of material from copper alloy fittings, heat exchanger tubes, tubing, and valve component types in treated water by using the Water Chemistry Control Program. Because this approach is consistent with the management of similar combinations of material and environment identified in the GALL Report, the staff finds this to be acceptable.

In the LRA, the applicant stated that it will manage loss of material from stainless steel fittings, piping, strainer, tubing, and valve component types by using the Diesel Fuel Monitoring Program (CNP AMP B.1.10). The staff documents its evaluation of this program in Section 3.0.3.2.4 of this SER. Because the Diesel Fuel Monitoring Program maintains oil systems free of contaminants (primarily water and particles) and provides additives to mitigate aging effects, the staff finds that this program adequately manages fouling and loss of material for components exposed to fuel oil.

In the LRA, the applicant stated that it will manage cracking of stainless steel fittings, piping, strainer, thermowell, and tubing component types exposed to lube oil by using the Oil Analysis Program (CNP AMP B.1.23). The staff documents its evaluation of this program in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that it will manage the loss of material from stainless steel fittings, piping, strainer, thermowell, tubing, and valve component types in lube oil by using the

Oil Analysis Program (CNP AMP B.1.23). The staff documents its evaluation of this program in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particles), the staff finds that this program adequately manages loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that it will manage loss of material from stainless steel fittings, piping, strainer, thermowell, tubing, and valve component types in treated water by using the Water Chemistry Control Program. The staff documents its evaluation of this program in Sections 3.0.3.2.15, 3.0.3.2.16, and 3.0.3.3.16 of this SER. Because this approach is consistent with the management of similar items identified in the GALL Report, the staff finds it to be acceptable.

In the LRA, the applicant stated that it will manage cracking and changes in material properties for elastomers in flex hose by using the Preventive Maintenance Program (CNP AMP B.1.25). The staff documents its evaluation of this program in Section 3.0.3.3.10 of this SER. The staff could not identify how the applicant would monitor changes in material properties. Therefore, the staff requested the applicant to clarify the method(s) used to monitor change in material properties of elastomers in the flex hose associated with the EDG. Material properties that could affect the performance of elastomers (e.g., hardness, flexibility) are not directly measured.

RAI 3.3.3-2

By letter dated August 20, 2004, in RAI 3.3.3-2, the staff asked the applicant to provide a basis for concluding that it will identify degradation of the elastomers before the intended function is compromised, or to provide a technical basis for the conclusion that the elastomers in question are not subject to these aging effects.

In its response dated September 2, 2004, the applicant stated that it will verify the flexibility of the hoses through physical manipulation of the hose during the visual inspection, thereby enhancing the inspector's ability to sense (both visually and through touch) a change in material properties that could affect the performance of the elastomers. The applicant stated that the Preventive Maintenance Program will use appropriate examination methods to ensure that degradation of flexible hoses in the EDG system will be identified before the intended function is compromised.

On the basis of its review of the applicant's response to RAI 3.3.3-2, the staff finds that the applicant has demonstrated that it will adequately manage change in material properties of flexible hoses resulting from hardening and flexibility in the EDG system so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it will manage fouling of copper-alloy heat exchanger tubes in treated water by using the CNP Water Chemistry Control Program. Because this approach is consistent with the management of similar items identified in the GALL Report, the staff finds it to be acceptable.

In the LRA, the applicant stated that there are no aging effects for the level glass gauge component type (glass) in an external environment of air or an internal environment of treated water. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that these components have no AERMs, the staff finds the absence of an AMP for glass to be acceptable.

On the basis of its review of the information provided in the LRA and the additional information in the applicant's response to the above RAIs, the staff finds the applicant has identified appropriate AMPs for managing the aging effects of the EDG system component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the EDG system components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.9 Security Diesel

Staff Evaluation

The staff reviewed the AMR of the security diesel system component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-9. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-9 of the LRA lists individual system components that are within the scope of license renewal and are subject to AMR. The component types evaluated in this section include bolting, compressor casing, expansion joints, filter housing, fittings, flanges, flex hoses, heat exchanger (shell), heat exchanger (tubes), heater housing, piping, pump casing, silencer, strainers, strainer housing, tanks, thermowells, tubing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel exposed to an external air environment is subject to loss of mechanical closure integrity. Carbon steel exposed to external air and internal exhaust gas environments is subject to loss of material and cracking-fatigue.

- Stainless steel exposed to an external air environment is subject to loss of mechanical closure integrity. Stainless steel exposed to an internal fuel oil environment is subject to cracking. Stainless steel exposed to an external soil environment is subject to loss of material.

- Copper alloy exposed to an external environment of lube oil or treated water is subject to fouling. Copper alloy exposed to an internal environment of treated water experiences fouling. Copper alloy exposed to an external environment of lube oil or treated water is subject to loss of material—wear.

- Elastomer exposed to an internal environment of fuel oil or treated water or an external environment of air is subject to the aging effects of change in material properties and cracking.

Section 3.3.2.3.12 provides the staff's evaluation of the loss of preload and cracking for closure bolting.

On the basis of its review of the information provided in the LRA, the staff finds that the aging effects of the above security diesel system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the security diesel system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-9 of the LRA identifies the following AMPs for managing the aging effects described above for the security diesel system:

- Bolting and Torquing Activities Program
- TLAA—Metal Fatigue Program
- System Testing Program
- Diesel Fuel Monitoring Program
- Preventive Maintenance Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.3.2, 4.3, 3.0.3.3.13, 3.0.3.2.4, and 3.0.3.3.10 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.9-1

Table 3.3.2-9 of the LRA identifies loss of material as an aging effect of stainless steel fittings and stainless steel/carbon steel piping in a soil environment (pages 3.3-115 and 3.3-120). The applicant identified the System Testing Program (CNP AMP B.1.37), page B-114 of the LRA, as the applicable AMP for managing these aging effects. However, this AMP does not define fitting or pipe condition or approximate rate of degradation as recommended in GALL AMPs XI.M28 or XI.M34 for buried fittings/piping. In RAI 3.3.2.1.9-1, the staff asked the applicant either to justify the exclusion of the buried piping/fitting condition assessment in CNP AMP B.1.37 in accordance with the GALL Report, or to revise the AMP accordingly.

In its response to RAI 3.3.2.1.9-1, by letter dated June 8, 2004, the applicant stated that the items referred to in LRA Table 3.3.2 9 are associated with the security diesel underground fuel oil tank and associated underground piping and fittings. The security diesel underground fuel oil tank and associated underground piping and fittings are periodically tested for leakage using timed system pressure tests. The applicant would discover leakage above the acceptance criteria or other degraded conditions in time to take corrective actions before loss of the system intended functions.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.9-1 acceptable. The applicant's response indicates that its periodic leakage testing would discover leakage above acceptance criteria or other degraded conditions in time to allow for corrective actions before a loss of system intended function. Although leakage tests define the underground piping systems' integrity at a snapshot in time, they may not reflect the piping and associated components' actual condition and rate of degradation during the period of extended operation. The applicant described an underground tank and piping inspection program (Buried Piping Inspection Program (CNP AMP B.1.6), page B-31 of the LRA) that appears to provide the necessary actions to quantify current piping condition and estimate a rate of degradation over the period of operation for components such as the security diesel underground components. The applicant needed to provide justification that leak rate test results reflect the actual rate of degradation and current condition of underground piping and fittings as defined in Table 3.3.2-9. The applicant needed to also justify not using an AMP similar to the Buried Piping Inspection Program (CNP AMP B.1.6) to manage the aging effects associated with buried carbon steel and stainless steel piping, tanks, and fittings defined in Table 3.3.2-9.

By letter dated October 18, 2004, the applicant states that the security diesel underground fuel oil tank and associated underground piping and fittings referred to in LRA Table 3.3.2-9 will be included in the Buried Piping Inspection Program described in LRA Section B.1.6. LRA Sections 3.3.2.1.9 and 3.3.2.2.11, as well as, Table 3.3.1 and Table 3.3.2-9 will be revised accordingly. The System Testing Program (CNP AMP B.1.37) will also be revised to reflect these changes. Based on its review, the staff finds that the applicant's inclusion of the security diesel underground fuel oil tank and associated underground piping and fittings in the Buried Piping Inspection Program will adequately evaluate the leak rate and current degradation of the underground piping and fittings. The staff finds the approach acceptable for managing the aging effects to the security diesel underground fuel oil tank and associated underground piping and fittings; therefore, the staff's concern described in RAI 3.3.2.1.9-1 is resolved.

RAI 3.3.2.1.9-2

Table 3.3.2-9 of the LRA (page 3.3-117) identifies the Preventive Maintenance Program (CNP AMP B.1.25), page B-82 of the LRA, as managing the change in material properties and cracking of flex hoses with an internal environment of fuel oil and treated water. The program description states that it will manage these aging effects by visual inspection and replacement as necessary. It is not apparent from the program description if internal and external surfaces will be inspected. Because of different internal and external environmental conditions, external examination may not indicate internal component condition. In RAI 3.3.2.1.9-2, the staff asked the applicant to explain how the visual examination referred to in the Preventive Maintenance Program will ensure management of internal aging effects of these components.

By letter dated June 8, 2004, the applicant stated that the Preventive Maintenance Program will manage the aging effects of change in material properties and cracking of the security diesel elastomer flex hoses exposed internally to fuel oil and treated water environments by performing visual inspection of both internal and external surfaces of these flex hoses, or replacing them, as appropriate. Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.9-2 acceptable because it clarifies the locations of intended visual inspections as both internal and external surfaces of flex hoses. This response resolves the concern expressed in RAI 3.3.2.1.9-2.

RAI 3.3.2.1.9-3

Table 3.3.2-9 of the LRA (page 3.3-118) identifies the System Testing Program (CNP AMP B.1.37), page B-114 of the LRA, as managing fouling of copper alloy heat exchanger tube components. For the same environment, component, and material, Table 3.3.2-8 (page 3.3.101) identifies the CNP Oil Analysis and Water Chemistry Control Programs as managing fouling and the loss of material. In RAI 3.3.2.1.9-3, the staff asked the applicant to justify the exclusion of the Water Chemistry Control and Oil Analysis Programs from management of the security diesel heat exchanger tube heat transfer function in Table 3.3.2-9.

By letter dated June 8, 2004, the applicant stated that although not explicitly credited in LRA Table 3.3.2 9 for managing fouling of the security diesel heat exchanger tubes, the Auxiliary Systems Water Chemistry Control Program includes the security diesel jacket cooling water system, as described in LRA Section B.1.40.3, and the Oil Analysis Program includes the security diesel lube oil system, as described in LRA Section B.1.23. The applicant inadvertently omitted these two programs from LRA Table 3.3.2-9. Additionally, during system testing, engine parameters, such as jacket water temperature, are monitored to assure that the heat exchangers are capable of removing heat loads. Therefore, monitoring performed by the System Testing Program, in conjunction with the Water Chemistry Control and Oil Analysis Programs, effectively manages fouling of the heat exchanger tubes. Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.9-3 acceptable, because the applicant has provided an acceptable justification (clerical error) as requested; therefore, the staff's concerns described in RAI 3.3.2.1.9-3 are resolved.

RAI 3.3.2.1.9-4

Table 3.3.2-9 of the LRA (page 3.3-119) identifies the System Testing Program (CNP AMP B.1.37), on page B-114 of the LRA, as managing loss of material of copper alloy heat exchanger tube components in a treated water external environment. For the same environment, component, and material, Table 3.3.2-8, page 3.3-102, identifies the Heat Exchanger Monitoring and Water Chemistry Control Programs as managing loss of material and loss of material—wear. In RAI 3.3.2.1.9-4, the staff asked the applicant to justify the exclusion of Water Chemistry Control and Heat Exchanger Monitoring Programs from management of the security diesel heat exchanger tube pressure boundary function in Table 3.3.2-9.

In its response to RAI 3.3.2.1.9-4, by letter dated June 8, 2004, the applicant stated that the security diesel is a nonseismic, nonsafety related system. Since a major component of the Heat Exchanger Monitoring Program is monitoring the seismic qualification of heat exchangers, this program is not credited for the nonseismic security diesel engine coolant heat exchangers or lube oil coolers. The security diesel engine coolant heat exchanger shell internal surfaces and tube external surfaces are exposed to treated water from the Lake Township water system. The Water Chemistry Control Program does not include Lake Township water chemistry. Consequently, neither the Heat Exchanger Monitoring Program nor the Water Chemistry Control Program would be appropriate for managing loss of material in these heat exchanger tubes. The security diesel engine lube oil cooler shell internal surfaces and tube external surfaces are exposed to lube oil, which is monitored by the Oil Analysis Program, as described in LRA Section B.1.23. The Oil Analysis Program detects and controls contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to corrosion, cracking, or fouling. Presence of engine coolant in the lube oil would indicate degradation of the lube oil cooler tubes. Additionally, during the periodic security diesel testing in accordance with the System Testing Program, operating parameters, such as oil pressure and jacket water temperature, are monitored. Abnormal indications and failure to meet acceptance criteria would result in corrective action. Therefore, since the Oil Analysis and System Testing Programs monitor the parameters that would indicate unacceptable aging effects, these programs are adequate for managing the effects of aging on the security diesel heat exchangers.

Based on its review, the staff did not find the applicant's response to RAI 3.3.2.1.9-4 acceptable. In RAI 3.3.2.1.9-4, the staff asked the applicant to justify the exclusion of the Water Chemistry Control and Heat Exchanger Monitoring Programs from management of aging of the security diesel heat exchanger tube pressure boundary function in Table 3.3.2-9. In addition, Table 3.3.2-9, page 119, defines the same material, environment, and aging effects combination (loss of material of copper alloy heat exchanger tube) for the diesel coolant heat exchanger and the diesel lube oil cooler heat exchanger. The security diesel engine coolant heat exchanger shell internal surfaces and tube external surfaces are exposed to treated water. The internal tube surfaces of the lube oil cooler heat exchanger are also exposed to treated water. The applicant's response defines different reasons for excluding the Water Chemistry Control and Heat Exchanger Monitoring Programs from management of the loss of material of a copper alloy in a treated water environment for each component.

The following text discusses separately the adequacy of the responses related to each heat exchanger.

<u>Diesel Coolant Jacket Water Heat Exchanger and Diesel Lube Oil Cooling Heat Exchanger.</u> The portion of the applicant's response to RAI 3.3.2.1.9-4 addressing these heat exchangers states the following:

> Since a major component of the Heat Exchanger Monitoring Program will be monitoring the seismic qualification of heat exchangers, this program is not credited for the non-seismic security diesel engine coolant heat exchangers or lube oil coolers.

The description of the applicant's Heat Exchanger Monitoring Program (CNP AMP B.1.13) states the following:

> The Heat Exchanger Monitoring Program will inspect heat exchangers for degradation using nondestructive examinations, such as eddy current inspections or visual inspections or, if appropriate, the heat exchanger will be replaced. If degradation is found, an evaluation will be performed to determine its effects on the heat exchanger design functions.

This statement, as well as the type of testing involved, indicates that CNP AMP B.1.13 manages several heat exchanger condition and functionality issues other than those affecting seismic qualification concerns. Other CNP AMP B.1.13 text supports this interpretation, stating the following:

> The aging effects for the heat exchanger tubes that will be managed by this program are loss of material and cracking. Eddy current inspection of the tubes will be performed every 10 years or more frequently if inspection results indicate a need for more frequent inspections.

This statement specifically addresses the AMP's purpose of managing the loss of material aging effect. Based on the program description and use of this AMP to manage loss of material in heat exchangers of the same material and environment, the applicant's justification for omitting the Heat Exchanger Monitoring Program is unsatisfactory. The applicant needed to provide further justification for omitting the Heat Exchanger Monitoring Program from the aging management of security diesel heat exchangers.

The applicant's response states that the Water Chemistry Control Program is not appropriate for managing the loss of material aging effect because Lake Township supplies the treated water used for the diesel jacket water cooling heat exchanger. However, industry experience has shown the importance of water chemistry control in managing loss of material in treated water systems. The GALL Report requirements repeatedly define water chemistry control as an important management technique to control the loss of material in a treated water environment. The initial provider of the treated water source does not lessen the importance of water chemistry control in managing loss of material. Operational tests as described in the System Testing Program (CNP B.1.37) do not control or minimize the rate of degradation, nor do functional tests detect changes in water chemistry that directly affect the rate of degradation. In a follow-up to RAI 3.3.2.1.9-4, the staff asked the applicant to provide further justification for not utilizing water chemistry control to manage the loss of material aging effect or to refer to an applicable AMP that manages water chemistry of the security diesel heat exchangers.

<u>Security Diesel Lube Oil Cooling Heat Exchanger</u>. The portion of the applicant's response to RAI 3.3.2.1.9-4 addressing this heat exchanger indicates that monitoring of oil condition and operational system testing provide adequate control and management of loss of material. Unlike water chemistry control, oil condition testing and functional testing do not manage

factors affecting the rate of degradation resulting from loss of material. In contrast, the AMPs defined by the applicant control the level of component degradation below some quantifiable level. Changes in heat exchanger performance or loss of tube integrity reflective of some minimal level of degradation must occur before actions can be taken to restore heat exchanger performance.

As indicated in RAI 3.3.2.1.9-4, the applicant uses the CNP Oil Analysis, Water Chemistry Control, and Heat Exchanger Monitoring Programs to manage the aging of other lube oil heat exchangers within the scope of license renewal. Use of the Water Chemistry Control Program and Heat Exchanger Monitoring Program minimizes the rate of component degradation and provides quantifiable data related to the actual internal condition of the heat exchanger. The applicant's aging management of the security diesel lube oil heat exchanger does neither. The staff asked the applicant to provide further justification for not using the Water Chemistry Control Program and Heat Exchanger Monitoring Program to manage the security diesel lube oil heat exchanger. The staff also asked the applicant to explain the differences in aging management of security diesel heat exchangers and EDG heat exchangers.

The GALL Report uses two main programs to minimize degradation of heat exchanger components in a treated water environment and maintain the pressure boundary function. Water chemistry control minimizes the rate of degradation from loss of material. Visual examination and nondestructive testing quantify the heat exchanger condition and verify the adequacy of water chemistry control. The programs defined by the applicant to manage the security diesel's heat exchanger components exposed to a treated water environment do not minimize aging effects to the same degree nor provide the same level of assurance in maintenance of the pressure boundary function. The applicant's AMPs detect the loss of material aging effect only after heat exchanger degradation has resulted in loss of pressure boundary integrity between the heat exchanger shell and tube sides or changes in heat transfer properties. The applicant's response does not justify the omission of a Water Chemistry Control Program or Heat Exchanger Monitoring Program from management of security diesel heat exchangers. The staff requested that the applicant explain why the security diesel heat exchanger's AMPs, as defined in Table 3.3.2-9, are as effective in managing of the loss of material aging effect as those defined in the GALL Report.

By letter dated October 18, 2004, the applicant responded to the two follow-up requests by expressing that the security diesel lube oil cooler is a shell and tube heat exchanger with lube oil internal to the shell and engine coolant (treated water) in the tubes. LRA Table 3.3.2-9 indicates that water chemistry control manages the loss of material of copper alloy heat exchanger (tubes) in a treated water internal environment. The line item in the table on page 3.3-119 of the LRA refers to the internal tube side of the security diesel lube oil cooler. The applicable aging management program is the Water Chemistry Control—Auxiliary Systems Water Chemistry Control Program (CNP AMP B.1.40.3).

The applicant also states that as indicated in LRA Tables 3.3-8 and 3.3-9 on pages 3.3-102 and 3.3-118, respectively, the Oil Analysis Program, is described in LRA Section B.1.23, manages the loss of material of both the security diesel and EDG lube oil cooler tube external surfaces. Therefore, water chemistry control does manage loss of material of the security diesel lube oil cooler tube internal surfaces, and the Oil Analysis Program manages the security diesel and EDG lube oil cooler tube external surfaces. To verify that aging effects are not occurring, the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41, will be used to inspect the security diesel lube oil cooler tube internal surfaces. No applicable comparison to the GALL Report exists for the security diesel lube oil heat exchanger tubes because the GALL Report does not evaluate these heat exchanger tubes or similar copper alloy components in a treated water environment. Furthermore, a comparison between the security diesel heat exchangers and EDG heat exchangers is not required, as the inclusion of the security diesel heat exchangers in the Chemistry One-Time Inspection Program will provide the necessary verification that loss of material of the heat exchanger tubes is not occurring. Based on its review, the staff finds that the applicant clarified the differences in approach for managing the internal and external surfaces of the heat exchanger and oil cooler tubes using the Water Chemistry Control—Auxiliary Systems Water Chemistry Control and the Oil Analysis Programs. By also including the Chemistry One-Time Inspection Program as an applicable AMP for these components, the applicant further ensures the proper management of the identified aging effect, loss of material. Therefore, the staff's concerns described in RAI 3.3.2.1.9-4 are resolved.

RAI 3.3.2.1.9-5

Table 3.3.2-9 of the LRA (page 3.3-124) identifies the Preventive Maintenance Program (CNP AMP B.1.25), page B-82 of the LRA, as managing the change in material properties and cracking of flex hoses with an internal environment of fuel oil. The program description states that it will manage these aging effects by visual inspection and replacement as necessary. It does not indicate whether the applicant will inspect internal and external surfaces. Because of different internal and external environmental conditions, the external condition may not represent the internal component condition. In RAI 3.3.2.1.9-5, the staff asked the applicant to explain how the visual examination referred to in the Preventive Maintenance Program will ensure management of internal aging effects.

By letter dated June 8, 2004, the applicant stated that the elastomer tubing listed in LRA Table 3.3.2-9 refers to plastic material used in the security diesel day tank level gauges. The internal surface of the clear plastic gauge used for local indication is evident during visual inspections. The internal surface of the plastic tubing used for remote indication is exposed to fuel oil and air. The Preventive Maintenance Program will manage the aging effects of change in material properties and cracking of this tubing by providing for visual inspection of both internal surfaces (at the connection point) and external surfaces of the tubing, or its replacement, as appropriate.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.9-5 acceptable, because the response clarifies the component and material in question and explains the visual examination capability related to internal surfaces. The response resolves the concerns related to assessment of internal material condition and environmental differences; therefore, the staff's concerns described in RAI 3.3.2.1.9-5 are resolved.

RAI 3.3.2.1.9-6

Table 3.3.2-9 of the LRA identifies the System Testing Program (CNP AMP B.1.37) as managing the loss of material on the internal surface of the security diesel heat exchanger shell in a treated water environment. The System Testing Program manages these aging effects by periodically starting the security diesel and operating it in accordance with manufacturer's recommendations, while monitoring system flow and system pressure. In RAI 3.3.2.1.9-6, the staff asked the applicant to describe how the System Testing Program manages aging effects on the internal surfaces of the heat exchanger shell.

By letter dated June 8, 2004, the applicant responded by stating the following:

> Testing of the security diesel generator is performed to demonstrate operability of the security diesel and to demonstrate the security diesel fuel oil system's ability to perform its intended functions. In addition to monitoring system flow, pressure, and temperature, monitoring for abnormal conditions, such as leakage, is also performed during the conduct of these system tests. Malfunctioning equipment, leakage, or failure to meet acceptance criteria during system testing would result in corrective action being taken. Loss of material on the treated water side of the heat exchanger shell would be detected in the form of pinhole leaks caused by isolated pitting or crevice corrosion. Monitoring for component leakage and system operating parameters under the System Testing Program provides assurance that loss of material from the internal surfaces of the heat exchanger shell will be identified during testing, prior to resulting in loss of function of the heat exchanger. This level of monitoring is commensurate with the safety significance of this non-seismic, non-safety-related component.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.9-6 acceptable. The GALL Report recommends two programs to minimize the degradation of heat exchanger components in a treated water environment and maintain the pressure boundary function. Water chemistry control minimizes the rate of degradation from the loss of material. Visual examination and nondestructive testing quantify the heat exchanger condition and verify the adequacy of water chemistry control. The programs defined by the applicant to manage the security diesel's heat exchanger shell exposed to a treated water environment do not minimize aging effects to the same degree nor provide the same level of assurance in maintenance of the pressure boundary function. The applicant's AMPs detect the loss of material aging effect only after heat exchanger degradation has resulted in a detectable loss of pressure boundary integrity or changes in heat transfer properties. The applicant's response does not justify the omission of the Water Chemistry Control Program or Heat Exchanger Monitoring Program from management of security diesel heat exchangers. The applicant needed to explain why the security diesel heat exchanger's AMPs, as defined in Table 3.3.2-9, are as effective in managing the loss of material aging effect as those defined in the GALL Report.

By letter dated October 18, 2004 the applicant stated the following:

> The security diesel jacket water coolers are shell and tube heat exchangers with engine coolant (treated water) internal to the tubes and Lake Township water (treated water) internal to the shell. Loss of material of the tube internal surfaces is managed by water chemistry control as indicated [on] Page 3.3-119 of LRA Table 3.3.2-9. The applicable aging management program is the Auxiliary Systems Water Chemistry Control Program, which is described in LRA Section B.1.40.3.
>
> Because Lake Township water (shell internal and tube external environments) chemistry is not controlled by CNP, a chemistry control program was not credited in the LRA. However, Lake Township water is provided by a municipality that is

a Michigan state-licensed public water supplier subject to provisions in the Michigan Department of Environmental Quality (MDEQ) *Safe Drinking Water Act 1976 PA 399, and Administrative Rules, as amended,* which include compliance with contaminant standards, and certification, monitoring, and reporting requirements. Lake Township water is potable water that has been treated with chemicals by the municipality. The municipality monitors contaminants such as chlorides and fluorides to maintain the water quality within MDEQ and Environmental Protection Agency regulations. Because the contaminant levels are maintained to ensure compliance with standards, significant aging effects are not expected. To verify the absence of significant aging effects, the Chemistry One-Time Inspection Program will include inspection of the surfaces of the security diesel jacket water coolers that are exposed to Lake Township water. The periodicity of further inspections will be based on the condition of the coolers in relation to their time-in-service. There is no applicable comparison to NUREG-1801 for the security diesel jacket water coolers since neither these coolers, nor any similar components, are evaluated by NUREG-1801.

Based on its review, the staff finds that the water chemistry of the Lake Township water supply has adequate controls to ensure its ability to prevent aging to the security diesel jacket water coolers that are exposed to Lake Township water. The applicant has also revised the LRA to include use of the Chemistry One-Time Inspection Program which will include inspection of the surfaces of the security diesel jacket water coolers that are exposed to Lake Township water. By also including the Chemistry One-Time Inspection Program as an applicable AMP for these components, the applicant further ensures that the identified aging effect of loss of material will be properly managed. Therefore, the staff's concern described in RAI 3.3.2.1.9-6 is resolved.

In the LRA, the applicant stated that it will manage the loss of material in carbon steel filter housing, fittings, heat exchanger shell, piping, pump casing, strainer, strainer housing, tubing, and valve component types using the Oil Analysis Program (CNP AMP B.1.23). The staff evaluation of this program appears in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates), the staff finds that this program adequately manages cracking and the loss of material for components exposed to lubricating oil.

For copper alloy filter housing, fittings, heat exchanger (shell), pump casing, strainer housing, and tubing component types exposed to ambient air, the applicant identified no aging effects. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for copper alloy components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage loss of material from copper-alloy filter housing, fittings, pump casing, strainer housing, and tubing component types by using the Diesel Fuel Monitoring Program (CNP AMP B.1.10). The staff evaluation of this program appears in Section 3.0.3.2.4 of this SER. Because the Diesel Fuel Monitoring Program maintains oil systems free of contaminants (primarily water and particles) and provides additives to mitigate aging effects, the staff finds that this program adequately manages fouling and the loss of material for components exposed to fuel oil.

In the LRA, the applicant stated that it will manage loss of material from carbon steel fittings, heater housing, piping, pump casing, tank, thermowell, and tubing component types in treated water by using the Water Chemistry Control Programs. The staff evaluation of the Water Chemistry Control Programs appears in Sections 3.0.3.2.15, 3.0.3.2.16, and 3.0.3.3.16 of this SER. Because this approach is consistent with the management of similar items identified in the GALL Report, the staff finds it to be acceptable.

In the LRA, the applicant stated that it will manage loss of material from copper-alloy fittings in contact with the soil by using the plant-specific System Testing Program (CNP AMP B.1.37). The staff evaluation of this program appears in Section 3.0.3.3.13 of this SER. Because similar aging effects occur for copper alloy materials in a soil environment and copper alloy materials in an internal fuel oil environment, and the system testing program scope includes the components of the security diesel system for this aging effect, the staff finds this to be acceptable.

In the LRA, the applicant stated that it will also use the Water Chemistry Control Program to manage loss of material from copper-alloy fittings, heat exchanger tubes, and tubing component types in treated water. Because this approach is consistent with the management of similar items identified in the GALL Report, the staff finds it to be acceptable.

For stainless steel exposed to ambient air, the applicant identified no AERMs. The component types affected are fittings, flange, flex hose, piping, tubing, and valves. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage loss of material from stainless steel fittings, flange, flex hose, piping, strainer, tubing, and valve component types by using the Diesel Fuel Monitoring Program (CNP AMP B.1.10). The staff evaluation of this program appears in Section 3.0.3.2.4 of this SER. Because the Diesel Fuel Monitoring Program maintains oil systems free of contaminants (primarily water and particles) and provides additives to mitigate aging effects, the staff finds that this program adequately manages fouling and loss of material for components exposed to fuel oil.

In the LRA, the applicant stated that it will manage cracking and changes in material properties for elastomers in flexible hose and tubing exposed to the air by using the Preventive Maintenance Program (CNP AMP B.1.25). The staff evaluation of this program appears in Section 3.0.3.3.10 of this SER. The staff could not identify how the applicant would monitor changes in material properties. The staff requested clarification of the method(s) used to monitor a change in material properties of elastomers in the flex hose associated with the security diesel. Material properties that could affect the performance of elastomers (e.g., hardness, flexibility) are not directly measured.

RAI 3.3.3-2

By letter dated August 20, 2004, in RAI 3.3.3-2, the staff asked the applicant to provide a basis for concluding that it will identify degradation of the elastomers before the intended function is compromised or to provide a technical basis for its conclusion that the elastomers in question are not subject to these aging effects.

In its response dated September 2, 2004, the applicant stated that it will verify the flexibility of the hoses through physical manipulation of the hose during the visual inspection, thereby enhancing the inspector's ability to sense (both visually and through touch) a change in material properties that could affect the performance of the elastomers. The applicant stated that the Preventive Maintenance Program will use appropriate examination methods to ensure that degradation of flexible hoses in the security diesel system will be identified before the intended function is compromised.

On the basis of its review of the applicant's response to RAI 3.3.3-2, the staff finds that the applicant has demonstrated that it will adequately manage change in material properties of flexible hoses resulting from hardening and flexibility in the security diesel system so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it will manage loss of material in copper alloy heat exchanger tubes by using the Oil Analysis Program (CNP AMP B.1.23). The staff evaluation of this program appears in Section 3.0.3.3.8 of this SER. Because the Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates), the staff finds that this program adequately manages cracking and the loss of material for components exposed to lubricating oil.

On the basis of its review of the information provided in the LRA and supplemental information provided by the applicant, the staff finds the applicant has identified appropriate AMPs for managing the aging effects of the security diesel system component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the security diesel system components identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.10 Postaccident Containment Hydrogen Monitoring System

Staff Evaluation

The staff reviewed the AMR of the PACHMS component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-10. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-10 of the LRA lists individual system components that are within the scope of license renewal and are subject to AMR. The component types evaluated in this section include analyzer body, bolting, filter, fittings, flex hoses, heat exchangers, moisture separator, orifices, piping, pump casing, and valves.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Stainless steel exposed to an internal air environment experiences cracking-fatigue. Stainless steel exposed to an internal oxygen environment experiences no aging effects.
- Carbon steel exposed to an internal oxygen environment experiences no aging effects.
- Elastomers exposed to an internal oxygen environment and external air environment are subject to change in material properties and cracking.
- Brass exposed to an oxygen internal environment experiences no aging effects.

Section 3.3.2.3.12 presents the staff's evaluation of the loss of preload and cracking for closure bolting.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2-1

In LRA Tables 3.3.2-1 through Table 3.3.2-11 for the auxiliary systems, the applicant listed several components having environments and applicable aging effects with associated AMPs. In the same columns, for the same component, material, and environment, the applicant listed no aging effects and no AMPs. For example, in Table 3.3.2-11, page 3.3-130, the applicant identified stainless steel bolting with a function of pressure boundary exposed to an external environment of air as experiencing loss of material managed by the Bolting and Torquing Activities Program. The same item in the table on page 3.3-130 for the same component exposed to the same environment has no identified aging effects and therefore requires no AMP. In addition, in Table 3.3.2-6, page 3.3-77, copper alloy valves exposed to an external condensation environment experience a loss of material. The same item in the table on page 3.3-77 for the same component exposed to the same environment has no identified aging effects and therefore requires no AMP. In RAI 3.3.2-1, the staff asked the applicant to explain these contradictory entries in the LRA tables.

By letter dated June 8, 2004, the applicant provided the following response to RAI 3.3.2-1 applicable to the PACHMS:

> In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, there are six instances in which a component type lists both an aging effect and "none" for the same material/environment combination. While this appears contradictory where occurring, it is not because each component type in the table actually represents

more than one component in the system. While the components are exposed to the same overall environment, specific conditions for individual components differ. The following paragraphs provide additional information for the instances applicable to the post-accident containment hydrogen monitoring system:

- LRA Table 3.3.2 10, Post-Accident Containment Hydrogen Monitoring System (Page 3.3 127)—stainless steel heat exchangers exposed to air internally (heat transfer and pressure boundary intended functions)

  Stainless steel heat exchangers exposed to air internally within the hydrogen analyzer sample panel "hot box" are exposed to a temperature slightly above the threshold for fatigue because they are heated by heat tracing. Therefore, cracking due to fatigue was conservatively identified as an aging effect requiring management for these stainless steel heat exchangers exposed to air internally. Stainless steel heat exchangers exposed to air internally, but outside the "hot box" are not exposed to temperatures above the threshold for fatigue. Therefore, no aging effects requiring management were identified for these stainless steel heat exchangers exposed to air internally.

- LRA Table 3.3.2 10, Post-Accident Containment Hydrogen Monitoring System (Page 3.3 129)—stainless steel valves exposed to air internally

  Stainless steel valves exposed to air internally in the sample flow path are exposed to a temperature slightly above the threshold for fatigue because they are heated by heat tracing. Therefore, cracking due to fatigue was conservatively identified as an aging effect requiring management for these stainless steel valves exposed to air internally. Stainless steel valves exposed to air internally in the reagent gas flow path are not exposed to temperatures above the threshold for fatigue. Therefore, no aging effects requiring management were identified for these stainless steel valves exposed to air internally.

Based on its review, the staff finds the applicant's response to RAI 3.3.2-1 acceptable because each component type in the table actually represents more than one component in the system, and while the components are exposed to the same overall environment, specific conditions for individual components differ as discussed by the applicant. Therefore, the staff's concerns described in RAI 3.3.2-1 are 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 RAI, the staff finds that the aging effects of the above PACHMS component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components of the PACHMS.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-10 of the LRA identifies the following AMPs for managing the aging effects described above for the PACHMS:

- TLAA—Metal Fatigue Program
- Preventive Maintenance Program

The staff's detailed review of these AMPs appears in Sections 4.3 and 3.0.3.3.10 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.10-1

In the LRA, Table 3.3.2-10 (page 3.3-127) identifies the Preventive Maintenance Program (CNP AMP B.1.25), page B-82 of the LRA, as managing a change in material properties and cracking of flex hoses with an internal environment of oxygen. The program description states that it will manage these aging effects by visual inspection and replacement as necessary. It is not apparent from the program description if internal and external surfaces will be inspected. Because of different internal and external environmental conditions, external examination may not indicate internal component conditions. In RAI 3.3.2.1.10-1, the staff asked the applicant to explain how the visual examination referred to in the Preventive Maintenance Program will ensure management of internal aging effects.

By letter dated June 8, 2004, the applicant replied as follows:

> The flex hoses listed in LRA Table 3.3.2-10 are small rubber hoses on the oxygen supply bottles. These bottles store pure oxygen, which is used as a reagent for the hydrogen analyzers. The hoses are exposed to oxygen internally and ambient air externally. Degradation of rubber from cracking and change in material properties can be caused by ultraviolet radiation, ionizing radiation, or thermal exposure. The internal hose surfaces are not exposed to ultraviolet radiation, since they are not exposed to light. The supply bottles and hoses are installed in a low radiation area. Therefore, the component dose will be substantially lower than the radiation dose threshold for elastomers (10^6–10^7 Rad). Both internal and external hose surfaces are close to the ambient air temperature of the auxiliary building. Since oxygen is also present in atmospheric (ambient) air, both internal and external surfaces of the hoses are exposed to oxygen. The external surface is exposed to an environment that is more severe than the internal environment (ultraviolet radiation); neither the internal nor external surfaces are exposed to elevated temperatures or high radiation. Therefore, inspection of the external surfaces is adequate to ensure detection of aging effects prior to loss of the pressure boundary intended function.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.10-1 acceptable. The applicant's response provides clarification as to the specific elastomer components requiring aging management, as well as the associated environmental conditions and preventive maintenance activities. The applicant's response indicates that external environmental conditions are more severe than the internal environmental conditions for the components of concern. Based on environmental conditions, the applicant indicated that visual inspection of the external surface will successfully manage the associated aging of these elastomer components and that inspection of the internal surface is not necessary. However, aging of elastomer components is a complex issue. The materials' specific chemical properties, as well as environmental conditions, affect the rate of aging. As the applicant's response indicates, internal and external environmental conditions are different, but the applicant's assumption that the material aging will occur more rapidly and be more apparent at the external surface has not been substantiated. A Sandia National Laboratory study titled, "Prediction of Elastomer Lifetimes from Accelerated Thermal Aging Experiments," by Kenneth T. Gillen and Roger L. Clough, indicates that oxygen concentration and pressure affect the oxidation rate of elastomers. The applicant's response to RAI 3.3.2.1.10-1 does not provide adequate information to substantiate aging management of these components by external visual observation alone. The staff requests that the applicant substantiate the adequacy of external surface visual examination in managing aging by providing details related to the applicable components' inspection/failure/repair frequency experienced during the plant's operating history.

By letter dated October 18, 2004, the applicant stated that a review of the operating experience for these hoses did not identify any pressure boundary failures due to elastomer degradation. However, prior to the period of extended operation, I&M will inspect internal hose ends and external surfaces of the post-accident hydrogen monitoring system reagent supply rubber hoses referred to in LRA Table 3.3.2-10. The periodicity of future inspections will be based on the condition of the hoses in relation to their time in service. Based on its review, the staff finds the applicant's assessment of operating history and conditions for verification and future inspections acceptable for managing the aging effects to the hoses; therefore, the staff's concern described in RAI 3.3.2.1.10-1 is resolved.

For stainless steel component types exposed to air, both ambient and internal, the applicant identified no AERMs. The component types affected are analyzer body, bolting, filter, heat exchanger, moisture separator, orifice, piping, pump casing, and valve. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of a program for stainless steel components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage cracking and changes in material properties for elastomers in flexible hose by using the Preventive Maintenance Program (CNP AMP B.1.25). The staff evaluation of this program appears in Section 3.0.3.3.10 of this SER.

The staff was unable to identify how the applicant would monitor changes in material properties. The staff requested clarification of the method(s) used to monitor a change in material properties of elastomers in the flex hose associated with the PACHMS. Material properties that could affect the performance of elastomers (e.g., hardness, flexibility) are not directly measured.

RAI 3.3.3-2

By letter dated August 20, 2004, in RAI 3.3.3-2, the staff asked the applicant to provide a basis for concluding that it will identify degradation of the elastomers before the intended function is compromised, or to provide a technical basis for its conclusion that the elastomers in question are not subject to these aging effects.

In its response dated September 2, 2004, the applicant stated that it will verify flexibility of the hoses through physical manipulation of the hose during the visual inspection, thereby enhancing the inspector's ability to sense (both visually and through touch) a change in material properties that could affect the performance of the elastomers. The applicant stated that the CNP Preventive Maintenance Program will use appropriate examination methods to ensure the identification of degradation of flexible hoses in the PACHMS before the intended function is compromised.

On the basis of its review of the applicant's response to RAI 3.3.3-2, the staff finds that the applicant has demonstrated that it will adequately manage change in material properties of flexible hoses resulting from hardening and flexibility in the PACHMS so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant identified no aging effects for stainless steel piping and valves exposed to an environment of hydrogen or nitrogen gas. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

For brass valves exposed to ambient air, the applicant identified no AERMs. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for brass valves exposed to ambient air to be acceptable.

On the basis of its review of the information provided in the LRA and the additional information provided by the applicant's response to the above RAI,, the staff finds the applicant has identified appropriate AMPs for managing the aging effects of the PACHMS component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the PACHMS components that are identified in this section. 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)(a).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.11 Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)

Staff Evaluation

The staff reviewed the AMR of the miscellaneous systems in scope for 10 CFR 54.4(a)(2) component, material, environment, and AERM combinations that are identified in the sections below titled "Aging Effects" and "Aging Management Programs." The applicant identified these combinations in LRA Table 3.3.2-11. For the combinations, the staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs with managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the programs.

Aging Effects

Table 2.3.3-11 of the LRA lists individual system components that are within the scope of license renewal and are subject to AMR. The component types evaluated in this section include bolting, condenser shell, evaporator housing, filter housing, flex hoses, heat exchanger (shell), heater coil, heater housing, level glass gauge, manifold (piping), orifices, piping, pump casings, strainer housing, tanks, thermowell, trap, tubing, valves, and ventilation unit housing.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Carbon steel exposed to an external air environment is subject to a loss of material and loss of mechanical closure integrity. Carbon steel exposed to a treated water, raw water (fresh), untreated water, or untreated water with boron environment is subject to loss of material. Carbon steel exposed to an internal environment of steam greater than 132 °C (270 °F) is subject to cracking-fatigue, loss of material, and loss of material— erosion.

- Stainless steel exposed to an external air environment is subject to loss of mechanical closure integrity or has no AERMs. Stainless steel exposed to an environment of internal treated water, untreated water with boron, or raw water (fresh) is subject to loss of material. Stainless steel exposed to an untreated water with boron or treated (borated) water environment is subject to loss of material and cracking. Stainless steel exposed to an internal untreated water or untreated water with boron environment is subject to loss of material. Stainless steel exposed to an internal environment of steam greater than 132 °C (270 F) is subject to cracking-fatigue, loss of material, and loss of material—erosion. Stainless steel exposed to an internal environment of treated water, untreated water, or treated borated water greater than 132 °C (270 F) is subject to cracking-fatigue, loss of material, and cracking.

- Cast iron exposed to an internal environment of steam greater than 132 °C (270 °F) is subject to cracking-fatigue and loss of material. Cast iron exposed to an environment of external air or internal treated water is subject to loss of material

- Copper alloy exposed to an internal environment of raw water (fresh), untreated water, or treated water experiences the aging effect of loss of material. Copper alloy exposed to an internal environment of steam greater than 132 °C (270 °F) experiences cracking-fatigue. Copper alloy exposed to a external air environment has no AERMs.

- Glass exposed to air, treated water, untreated water, or untreated water with boron experiences no aging effects.

- Molded plastic exposed to an air or treated water environment experiences change in material properties and cracking.

Section 3.3.2.3.12 presents the staff's evaluation of the loss of preload and cracking for closure bolting.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2-1

In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, the applicant listed several components having environments and applicable aging effects with associated AMPs. In the same columns, for the same component, material, and environment, the applicant listed no aging effects and no AMPs. For example, in Table 3.3.2-11 (page 3.3-130), the applicant identified stainless steel bolting with a function of pressure boundary exposed to an external environment of air as experiencing loss of material which is managed by the Bolting and Torquing Activities Program. The same item in the table on page 3.3-130 for the same component exposed to the same environment has no aging effects listed and therefore requires no AMP. In addition, in Table 3.3.2-6 (page 3.3-77), copper alloy valves exposed to an external condensation environment experience a loss of material. The same item in the table on page 3.3-77 for the same component exposed to the same environment has no aging effects listed and therefore requires no aging management. In RAI 3.3.2-1, the staff asked the applicant to explain these contradictory entries in the LRA tables.

By letter dated June 8, 2004, the applicant provided the following response applicable to the miscellaneous systems for RAI 3.3.2-1:

> In LRA Tables 3.3.2-1 through 3.3.2-11 for the auxiliary systems, there are six instances in which a component type lists both an aging effect and "none" for the same material/environment combination. While this appears contradictory where occurring, it is not because each component type in the table actually represents more than one component in the system. While the components are exposed to the same overall environment, specific conditions for individual components differ. The following paragraphs provide additional information for the instances applicable to the miscellaneous systems:
>
> - LRA Table 3.3.2 11, Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2) (Page 3.3 130)—stainless steel bolting exposed to air externally
>
>   Stainless steel bolting exposed to air in high temperatures systems may experience loss of pre-load from thermal effects. Therefore, loss of mechanical closure integrity was identified as an aging effect requiring management for this stainless steel bolting exposed to air in high temperature systems. Stainless steel bolting in low temperature systems will

not experience loss of pre-load from thermal effects. Also, components in these systems are not exposed to significant vibration, such as from a diesel engine. Therefore, no aging effects requiring management were identified for this stainless steel bolting exposed to air in low temperature systems.

Based on its review, the staff finds the applicant's response to RAI 3.3.2-1 acceptable because each component type in the table actually represents more than one component in the system, and while the components are exposed to the same overall environment, specific conditions for individual components differ as discussed by the applicant. Therefore, the staff's concerns described in RAI 3.3.2-1 are 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 RAI, the staff finds that the aging effects of the above miscellaneous systems in scope for 10 CFR 54.4(a)(2) component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the above components in the miscellaneous systems in scope for 10 CFR 54.4(a)(2).

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.3.2-11 of the LRA identifies the following AMPs as managing the aging effects described above for the miscellaneous systems in scope for 10 CFR 54.4(a)(2):

- Boric Acid Corrosion Prevention Program
- System Walkdown Program
- Bolting and Torquing Activities Program
- Water Chemistry Control Program
- Flow-Accelerated Corrosion Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.2.1, 3.0.3.3.14, 3.0.3.3.2, 3.0.3.3.16, and 3.0.3.1 of this SER, respectively.

During its review, the staff determined that it needed additional information to complete its evaluation.

RAI 3.3.2.1.11-1

In the LRA, Table 3.3.2-11 (pages 3.3-130 to 3.3-152) identifies the System Walkdown Program (CNP AMP B.1.38), page B-119, for management of various aging effects for several components with different internal and external environments. The System Walkdown Program description states that the program is applicable only to situations where the internal and external environments are the same. A component's external condition may not be representative of internal material conditions in differing environments. In RAI 3.3.2.1.11-1, the staff asked the applicant to justify use of the System Walkdown Program to manage aging effects for all components identified in Table 3.3.2-11 with different internal and external environments and also to explain how a system walkdown can inspect and verify proper management of all internal aging effects.

By letter dated June 8, 2004, the applicant replied as follows:

> The statement in the LRA Section B.1.38 Scope section is, "The program is also credited with managing loss of material from internal surfaces, for situations where the external surface condition is considered representative of the internal surface condition and both have the same environment." This statement does not indicate that the System Walkdown Program is only applicable to situations where the internal and external environments are the same. The Scope section also states, "This program includes inspections of external surfaces of CNP structures and components within the scope of license renewal." This inspection of external surfaces addresses components subject to aging management review for 10 CFR 54.4(a)(2), as indicated in LRA Table 3.3.2-11, where the System Walkdown Program is credited as the sole aging management program regardless of the environment. For these components, the concern is the impact of spray or leakage from non-safety-related components on safety related equipment. Provided the effect of non-safety related component failures on safety related equipment is managed, safety related equipment will continue to be capable of performing its required intended functions. The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. This program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short term exposure is not a concern for passive components such as valve bodies and piping. Active safety related component failures due to short term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging related degradation of active components, it also applies to detecting degradation of the same active components due to aging related degradation of non-safety related components.

Based on the information presented above, the applicant indicated that the System Walkdown Program is adequate as an AMP because it includes periodic walkdowns that will detect conditions that could result in failures caused by exposure to spray or wetting regardless of the internal or external environments and their aging effects.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.11-1 acceptable. The applicant's response indicates that the System Walkdown Program is applicable to situations other than when internal and external environments of the component or system are the same (for example, inspections of external surfaces of plant structures within the scope of license renewal). Use of the System Walkdown Program to assess component or system external conditions is a recognized and accepted aging management approach and is not an issue or concern. The staff's specific concern, described in RAI 3.3.2.1.11-1, is the apparent aging management of the internal environments of components/systems by visual inspection of external surfaces if environmental differences exist between internal and external surfaces. While external inspection of component condition (e.g. pipes, valves) can indicate the components' internal condition, this is generally not the case until internal degradation results in loss of component integrity as might be indicated by a system leak. In such an example, the leak indicates failure of the structure and or component. The following part of the applicant's response indicates that the applicant considers component/system aging management and leak (size and time of spray) management to be equivalent:

> This program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short term exposure is not a concern for passive components such as valve bodies and piping. Active safety related component failures due to short term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence.

In addition, the applicant's response indicates that the current program will manage the size and duration of leakage so as not to impact the operation of active safety components. Neither the GALL Report nor the industry recognizes leak management as an acceptable aging management methodology.

The applicant has not provided sufficient information to demonstrate that the System Walkdown Program will effectively manage aging effects on internal surfaces of various components in miscellaneous systems because leakage indicates failure of the structure and or component. The staff asked the applicant to provide further justification for the use of the System Walkdown Program to manage aging effects for all components identified in Table 3.3.2-11 with different internal and external environments sufficiently to maintain the intended function of the components and ensure that operation of safety related equipment will not be jeopardized during the period of license renewal. This was identified by the staff as Open Item 3.3.2.1.11-1.

By letter dated January 21, 2005, the applicant provided additional information in response to Open Item 3.3.2.1.11-1.

> As shown in LRA Table 3.3.2-11, in addition to System Walkdown Program, the Water Chemistry Control Program will manage the effects of aging on the components with an internal environment of treated water, except for level glass gauges and molded plastic tanks. Because the glass in the level gauges is inherently resistant to potential aging effects in air, treated water, raw or untreated water, or untreated borated water environments, it has no aging effects requiring management. The molded plastic tanks in the ice condenser system are exposed to an internal treated water environment (i.e., glycol mixture) that is monitored by the Auxiliary Systems Water Chemistry Control Program described in LRA Section B.1.40.3.

Additionally, as indicated in LRA Table 3.3.2-11, the Flow-Accelerated Corrosion Program will also manage the effects of aging on components with an internal steam environment, except for copper heater coils, cast iron strainer housings and carbon steel traps. I&M will include the auxiliary steam system copper heater coils, cast iron strainer housings, and carbon steel traps exposed to an internal steam environment in the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41.

The remaining components in LRA Table 3.3.2-11 with differing internal and external environments that credit only the System Walkdown Program for aging management are exposed to internal raw or untreated water environments. The following table identifies the fluid-filled mechanical systems that contain these components.

SYSTEM CODE	SYSTEM NAME
CF	Chemical Feed
CONT	Containment
DRAIN	Process Drains
LTW	Lake Township Water
NESW	Non-Essential Service Water
NS	Nuclear Sampling
PASS	Post-Accident Sampling
RMS	Radiation Monitoring
RWD	Radioactive Waste Disposal
SD	Station Drainage

The following discussion provides additional basis for acceptability of other programs for managing the effects of aging on the CF, LTW, NESW, and NS systems that have components containing raw or untreated water.

1. The CF system contains water treated with chemicals to reduce corrosion in the steam generators. This environment was conservatively classified as untreated water although it is actually chemically treated.

2. The LTW system contains water that has been chemically treated by the municipality prior to being used at the site, but was conservatively classified as untreated water in the aging management review. Because LTW chemistry is not controlled by CNP, a chemistry control program was not credited in the LRA. However, as documented in I&M's supplemental response to RAI 3.3.2.1.9-6 in this letter, the extent of aging effects on security diesel system components containing LTW will be confirmed by the Chemistry One-Time Inspection Program, which will inspect a representative sample of 10 CFR 54.4(a)(2) components in the LTW system.

3. The NS system contains heat exchangers exposed to an internal raw water (NESW) environment. The NESW system has the same suction source and is

chemically treated in the same manner as the essential service water (ESW) system. The Service Water System Reliability Program will manage the effects of aging on 10 CFR 54.4(a)(2) components containing NESW, because these components are fabricated from the same materials and are exposed to the same environments as components in the ESW system.

The remaining systems (CONT, DRAIN, PASS, RMS, RWD, and SD) have copper alloy, carbon steel, stainless steel, or glass components that may be pressurized and contain raw or untreated water. As discussed previously, glass exposed to raw or untreated water exhibits no aging effects requiring management. I&M will include these 10 CFR 54.4(a)(2) components that are subject to aging management review in the Chemistry One-Time Inspection Program.

Loss of material, if any, from the 10 CFR 54.4(a)(2) components discussed above is expected to progress slowly. The one-time inspection of these components will provide assurance that loss of material is occurring at a rate slow enough to ensure that the intended functions of the components will be maintained during the period of extended operation. This one-time inspection will be performed near the end of the current operating term. The visual inspections will identify indications of loss of material. If loss of material is identified, an evaluation will be performed to confirm that the rate is sufficiently slow that loss of intended function will not occur during the period of extended operation. For material and environment combinations with no evidence of loss of material or with very gradual loss of material, no further actions will be taken. For material and environment combinations with loss of material rates such that loss of intended function could occur during the period of extended operation, corrective actions will be taken in accordance with the Corrective Action Program. Appropriate corrective actions may consist of component replacement or additional inspections for components with the material and environment combination in which the excessive loss of material is found.

The supplemental response is reasonable and acceptable to the staff because the applicant has provided sufficient information to demonstrate that aging effects on internal surfaces of various components in miscellaneous systems will be effectively managed by the application of a combination of the Flow-Accelerated Corrosion Program, Chemistry One-Time Inspection Program, Water Chemistry Control Program, and the Service Water System Reliability Program. The application of the Chemistry One-Time Inspection Program is appropriate for those components where the loss of material is expected to progress slowly and the applicant has identified that the inspection will be performed near the end of the current operating term with appropriate corrective actions. On the basis of the supplemental information submitted by the applicant, all issues related to Open Item 3.3.2.1.11-1 are resolved. The application of the Chemistry One-Time Inspection Program discussed above is specified in Commitment #39 in Appendix A of this SER..

RAI 3.3.2.1.11-2

Table 3.3.2-11 of the LRA (page 3.3-131) identifies the System Walkdown Program (CNP AMP B.1.38), page B-119, as managing the loss of material of a stainless steel filter housing in untreated water with a boron internal environment. This is an example of one of several stainless steel components for which the applicant identified the System Walkdown Program as managing the loss of material in internal environments. The description of the System Walkdown Program does not address aging management for the loss of material of stainless steel. In RAI 3.3.2.1.11-2, the staff asked the applicant to justify the use of the System Walkdown Program in managing the loss of material of stainless steel components exposed to an untreated water with boron internal environment for each component in Table 3.3.2-1 and also to explain how a system walkdown can inspect and verify proper management of all internal aging effects.

By letter dated June 8, 2004, the applicant replied to RAI 3.3.2.1.11-2 as follows:

> Management of internal loss of material in stainless steel components was an inadvertent omission from LRA Section B.1.38. This aging effect was included in the aging management review for filter housings in the radioactive waste disposal system cited in this RAI as well as other stainless steel components.
>
> For the 10 CFR 54.4(a)(2) component types in LRA Table 3.3.2 11 that credit the System Walkdown Program, the concern is the impact of spray or leakage from non-safety-related components onto safety-related equipment. Provided the effect of non-safety related component failures on safety-related equipment is managed, safety related equipment will continue to be capable of performing its required intended functions.
>
> The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. This program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short term exposure is not a concern for passive components such as valve bodies and piping. Active safety-related component failures due to short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states, "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging-related degradation of active components, it also applies to detecting degradation of the same active components due to aging related degradation of non-safety related components.
>
> Based on the information presented above, the System Walkdown Program is adequate as an aging management program, because it includes periodic walkdowns that will detect conditions that could result in failures caused by exposure to spray or wetting, regardless of the internal or external environments.

The staff accepts the applicant's response to include aging management for the omitted stainless steel components. However, the staff does not accept the applicant's response to RAI 3.3.2.1.11-2 concerning the use of the System Walkdown Program to provide adequate aging management. The applicant's response to RAI 3.3.2.1.11-2 appears to equate leak management of nonsafety related systems/components to aging management of the same system/component.

The response indicates that the System Walkdown Program will manage the size and magnitude of nonsafety related system component leaks sufficiently to ensure minimal impact on active safety related components. This meaning is substantiated by the applicant's interpretation of the NRC's SOC for the final rule for 10 CFR Part 54, which it cites in its response.

Generally, the staff interprets this statement to indicate that failure of an active component resulting from aging is readily discovered and repaired because of the established effectiveness of standard industry maintenance programs, as well as active monitoring systems. The applicant's response appears to equate failure of an active safety related component resulting from internal component failures to a loss of component functionality caused by nonsafety related system leakage. The applicant's response further indicates that management of the size and duration of nonsafety related system leakage would sufficiently ensure functionality of safety related system active components. Managing the size and duration of spray is not analogous to preserving the integrity of the pressure boundary and does not provide the same level of assurance that the functionality of safety related system components will be maintained. Neither the GALL Report nor the industry recognizes leak management of nonsafety related systems as an acceptable aging management methodology.

The staff asked the applicant to provide additional justification that the System Walkdown Program will maintain the intended pressure boundary function for each stainless steel component defined in Table 3.3.2-11 with an internal environment of untreated borated water, an external air environment, and the loss of material as the AERM.

By letter dated October 18, 2004, the applicant provided additional information in response to RAI 3.3.2.1.11-2.

> As indicated in I&M's supplemental response to RAI 3.3.2.1.11-1, the stainless steel components listed in LRA Table 3.3.2-11 with an internal environment of untreated water with boron and an external air environment will be included in the Chemistry One-Time Inspection Program to provide assurance that the pressure boundary function will be maintained through the period of extended operation.

The supplemental response is reasonable and acceptable to the staff because the applicant has provided sufficient information to demonstrate that it will effectively manage aging effects on internal surfaces of stainless steel components in miscellaneous systems by the application of the Chemistry One-Time Inspection Program. On the basis of the supplemental information submitted by the applicant, all issues related to RAI 3.3.2.1.11-2 are resolved.

RAI 3.3.2.1.11-3

Table 3.3.2-11 of the LRA identifies the CNP System Walkdown Program as managing loss of material, cracking, and change in material properties for the internals of various components such as condenser shell, evaporator housing, filter housing, flex hose, heat exchanger shell, heater coil, heater housing, manifold piping, orifice, piping, pump casing, strainer housing, tanks, thermowell, traps, tubing, valves, and ventilation unit housings. The System Walkdown Program entails inspections of accessible surfaces during walkdowns. In RAI 3.3.2.1.11-3, the staff asked the applicant to explain how the System Walkdown Program will detect the loss of material on the internal surfaces of these components.

By letter dated June 30, 2004, the applicant stated the following:

> The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. These inspections will detect loss of material on the internal surfaces of these components by observing for evidence of leakage on the external surfaces of the components. For those components where the System Walkdown Program is credited as the aging management program for the internal surfaces, the concern is the impact of spray or leakage from nonsafety-related components on safety-related equipment. By managing the aging effects of nonsafety-related component failures on safety-related equipment, safety-related equipment will continue to be able to perform required intended functions.
>
> The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. The System Walkdown Program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short-term exposure is not a concern for passive components such as valve bodies and piping. Active safety-related component failures due to short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging-related degradation of active components, it also applies to detecting degradation of the same active components due to aging-related degradation of nonsafety-related components.

In the information presented above, the applicant stated that the System Walkdown Program is adequate as an AMP for managing the loss of material on the internal surfaces of components listed in LRA Table 3.3.2-11 because it includes periodic walkdowns that will detect and correct conditions that could result in failures caused by exposure to spray or wetting.

Based on its review, the staff does not find the applicant's response to RAI 3.3.2.1.11-3 acceptable. In the following part of its statement, the applicant's response appears to equate leak management of nonsafety related systems/components to aging management of the same system/component:

> The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. This program includes periodic walkdowns that will detect and correct failures that could result in long term exposure to spray or wetting. Short term exposure is not a concern for passive components such as valve bodies and piping. Active safety related component failures due to short term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence.

The applicant's response indicates that the System Walkdown Program will manage the size and magnitude of nonsafety related system component leaks sufficiently to ensure minimal impact on active safety related components. This meaning is substantiated by the applicant's interpretation of the NRC's SOC for the final rule for 10 CFR Part 54, which the applicant quoted in its response.

Generally, the staff interprets this statement to indicate that failure of an active component resulting from aging is readily discovered and repaired because of the established effectiveness of standard industry maintenance programs, as well as active monitoring systems. The applicant's response appears to equate failure of an active safety related component resulting from internal component failures to a loss of component functionality caused by nonsafety related system leakage. The applicant's response also indicates that management of the size and duration of nonsafety related system leakage would sufficiently ensure functionality of safety related system active components. Managing the size and duration of spray is not analogous to preserving the functionality of internal components and does not provide the same level of assurance that the functionality of safety related system components will be maintained. Neither the GALL Report nor the industry recognizes leak management of nonsafety related systems as an acceptable aging management methodology.

To further clarify RAI 3.3.2.1.11-3, the staff asked the applicant for additional justification that the System Walkdown Program will maintain the specified functions for the internals of various components such as condenser shell, evaporator housing, filter housing, flex hose, heat exchanger shell, heater coil, heater housing, manifold piping, orifice, piping, pump casing, strainer housing, tanks, thermowell, traps, tubing, valves, and ventilation unit housings listed in Table 3.3.2-11 for which the applicant designated the System Walkdown Program to manage the aging effects of loss of material, cracking, and change in material properties.

By letter dated October 18, 2004, the applicant referenced the supplemental response to RAI 3.3.2.1.11-1 to resolve RAI 3.3.2.1.11-3.

The supplemental response is reasonable and acceptable to the staff because the applicant has provided sufficient information in response to RAI 3.3.2.1.11-1 to demonstrate that it will effectively manage aging in the internal surfaces of various components in miscellaneous systems by the application of a combination of the Flow-Accelerated Corrosion Program, Chemistry One-Time Inspection Program, Water Chemistry Control Program, and the Service Water System Reliability Program. On the basis of the supplemental information submitted by the applicant, all issues related to RAI 3.3.2.1.11-3 are resolved.

In the LRA, the applicant stated that it will manage the loss of material for carbon steel bolting exposed to ambient air by using the Boric Acid Corrosion Prevention (CNP AMP B.1.4) and System Walkdown (CNP AMP B.1.38) Programs. The staff's evaluation of these programs appears in Sections 3.0.3.2.1 and 3.0.3.3.14 of this SER, respectively. Because this approach is similar to the management recommended by the GALL Report for this material-environment combination in other auxiliary systems, the staff finds the use of the System Walkdown Program to be acceptable for these components.

In the LRA, the applicant stated that it will manage the loss of material for carbon steel component types exposed to ambient air by using the System Walkdown Program. The applicant will use this program for condenser shell, evaporator housing, heater housing, orifice, piping, pump casing, strainer housing, tank (including coated carbon steel), thermowell, trap, valve, and ventilation unit housing component types. The applicant will also use the System Walkdown Program to manage the loss of material for the internal surfaces of the ventilation unit housing made of carbon steel. The staff finds this to be acceptable.

For stainless steel exposed to ambient air, the applicant identified no AERM for the bolting, filter housing, flex hose, manifold, orifice, piping, pump casing, strainer housing, tank, thermowell, tubing, and valve component types. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for stainless steel components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage the loss of material for carbon steel component types exposed to treated water (internal) by using the System Walkdown (CNP AMP B.1.38) and Water Chemistry Control (CNP AMP B.1.40) Programs. The staff presents its evaluation of the System Walkdown Program in Section 3.0.3.3.14. In addition, the staff documents its evaluation of the Water Chemistry Control Program in Sections 3.0.3.2.15, 3.0.3.2.16, and 3.0.3.3.16 of this SER. The applicant uses this program for condenser shell, evaporator housing, heater housing, orifice, piping, pump casing, strainer housing, tank (including coated carbon steel), thermowell, and valve component types. The staff finds the use of the System Walkdown and Water Chemistry Control Programs to be acceptable for these component types.

For copper alloy heat exchanger (shell), heater coil, manifold, piping, tubing, and valve component types exposed to ambient air, the applicant identified no aging effects. Because the applicant did not identify any AERMs, and this is consistent with industry experience, the staff finds the absence of an AMP for copper alloy components exposed to ambient air to be acceptable.

In the LRA, the applicant stated that it will manage the loss of material for copper alloy heat exchanger shell, manifold, piping, tubing, and valve component types in treated water by using the System Walkdown and Water Chemistry Control Programs. The staff finds the use of the

System Walkdown and Water Chemistry Control Programs to be acceptable for these component types.

In the LRA, the applicant stated that it will manage the loss of material for the copper alloy heater coil exposed to steam greater than 132 °C (270 °F) by using the System Walkdown Program. Although the applicant cited a precedent, the staff could not confirm its applicability in this case. It was not clear to the staff how the System Walkdown Program would detect this aging effect before failure of the component. However, the resolution of related RAI 3.3.2.1.11-3 clarifies these issues for the staff.

In the LRA, the applicant stated that it will manage the loss of material for stainless steel in treated water by using the CNP System Walkdown and Water Chemistry Control Programs. This applies to the manifold (piping), orifice, piping, pump casing, tank, thermowell, tubing, and valve component types. Because it is similar to the management recommended by the GALL Report for this material-environment combination in other auxiliary systems, the staff finds the use of the System Walkdown and Water Chemistry Programs to be acceptable for these component types.

In the LRA, the applicant stated that it will manage cracking and the loss of material for stainless steel manifold, piping, pump casing, thermowell, tubing, and valves exposed to treated, borated water by using the Water Chemistry Control Program with the System Walkdown Program. Because this approach is similar to the management recommended by the GALL Report for this material-environment combination in other auxiliary systems, the staff finds the use of the System Walkdown and Water Chemistry Programs to be acceptable for these component types.

In the LRA, the applicant stated that it will manage the loss of material for cast iron pump casing and strainer housing component types in air by using the System Walkdown Program. Because the aging effects for this material are similar to those for carbon steel in this environment and because the program is acceptable for management of this aging effect in carbon steel, the staff finds its use acceptable.

In the LRA, the applicant stated that it will manage the loss of material and cracking in stainless steel tubing and valves exposed to treated water greater than 132 °C (270 °F) and treated, borated water greater than 132 °C (270 °F) by using a water chemistry control program consistent with the GALL Report. Because this approach is similar to the management of cracking of stainless steel in this environment in other non-Class 1 systems, the staff finds the use of the System Walkdown and Water Chemistry Control Programs to be acceptable for these component types.

In the LRA, the applicant stated that there are no aging effects for the level glass gauge component type (glass) in an external environment of air or an internal environment of treated water, untreated water or untreated water with boron. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that these components have no AERMs, the staff finds the absence of an AMP for glass 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 RAIs, the staff finds that the applicant has identified appropriate AMPs for managing the aging effects of the miscellaneous systems in scope for 10 CFR 54.4(a)(2) component types that are addressed in this section. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the miscellaneous systems in scope for 10 CFR 54.4(a)(2) components that are identified in this section. 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.3.2.3.12 Generic Issues for the Auxiliary Systems

For bolting in the auxiliary systems, the applicant did not address the aging effects of cracking due to SCC for high-strength bolts or the loss of preload. The staff asked the applicant to address these issues for auxiliary system bolting. The staff discusses its evaluation of the applicant's response and resolution of the staff's concerns as part of the evaluation of RAI B.1.2-1 in Section 3.0.3.3.2 of this SER.

3.3.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the auxiliary system components that are within the scope of license renewal and subject to an AMR 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).

3.4 Aging Management of Steam and Power Conversion Systems

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion systems components and component groups associated with the following systems:

- main feedwater system
- main steam system
- auxiliary feedwater system
- blowdown system

3.4.1 Summary of Technical Information in the Application

In Section 3.4 of the LRA, the applicant provided the results of the AMR of the main feedwater, main steam, AFW, and blowdown system components and component types listed in Tables 2.3.4-1 through 2.3.4-4 of the LRA. The applicant also listed the materials, environments, AERMs, and AMPs associated with each system.

In Table 3.4.1, "Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801," of the LRA, the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the main feedwater, main steam, AFW, and blowdown system components and component types. In Section 3.4.2.2 of the LRA, the applicant provided information concerning Table 3.4.1 components for which the GALL Report recommends further evaluation.

3.4.2 Staff Evaluation

The staff reviewed Section 3.4 of the LRA to understand the applicant's review process. The staff determined whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the main feedwater, main steam, AFW, and blowdown system components that are within the scope of license renewal and subject to an AMR, in order that their intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is appropriate and that the applicant identified the necessary GALL AMRs. The staff summarizes its audit and review findings in Section 3.4.2.1 of this SER.

The staff also audited those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations are consistent with the acceptance criteria in Section 3.4.3.2 of the SRP-LR. The staff summarizes its audit and review findings in Section 3.4.2.2 of this SER.

The staff conducted a technical review of the remaining AMRs that are not consistent with the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects and whether it listed the appropriate aging effects for the combination of materials and environments specified. The staff summarizes its audit and review findings in Section 3.4.2.3 of this SER.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they adequately describe the programs credited with managing or monitoring aging for the steam and power conversion systems.

Table 3.4-1 below summarizes 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 for Steam and Power Conversion System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings in main feedwater line, steamline, and AFW piping (PWR only) (Item Number 3.4.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.1)
Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel heads, and shells (except main steam system) (Item Number 3.4.1-2)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water chemistry and one-time inspection	Water Chemistry Control Program (B.1.40); Wall Thinning Monitoring Program (B.1.39)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.2)
AFW piping (Item Number 3.4.1-3)	Loss of material due to general, pitting, and crevice corrosion; MIC; and biofouling	Plant specific	Service Water System Reliability Program (B.1.29), Water Chemistry Control Program—Primary and Secondary Water Chemistry Programs (B.1.40.1), and System Testing Program(B.1.37)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.3)
Oil coolers in AFW system (lubricating oil side possibly contaminated with water) (Item Number 3.4.1-4)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion; MIC	Plant specific	Oil Analysis (B.1.23)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.5)
External surface of carbon steel components (Item Number 3.4.1-5)	Loss of material due to general corrosion	Plant specific	System Walkdown Program (B.1.38)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.4)
Carbon steel piping and valve bodies (Item Number 3.4.1-6)	Wall thinning due to Flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated Corrosion Program (B.1.12)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Carbon steel piping and valve bodies in main steam system (Item Number 3.4.1-7)	Loss of material due to pitting and crevice corrosion	Water chemistry	Water Chemistry Control Program (B.1.40); Wall Thinning Monitoring Program (B.1.39)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)
Closure bolting in high-pressure or high-temperature systems (Item Number 3.4.1-8)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	System Walkdown Program (B.1.38); Bolting and Torquing Activities Program (B.1.2)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/ condensers by open-cycle cooling water (Item Number 3.4.1-9)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion; MIC; biofouling; and buildup of deposits due to biofouling	Open-cycle cooling water system	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/ condensers by closed-cycle cooling water (Item Number 3.4.1-10)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-cycle cooling water system	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)
External surface of aboveground condensate storage tank (Item Number 3.4.1-11)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Aboveground carbon steel tanks	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)
External surface of buried condensate storage tank and AFW piping (Item Number 3.4.1-12)	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	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1) Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2.5)
External surface of carbon steel components (Item Number 3.4.1-13)	Loss of material due to boric acid corrosion	Boric acid corrosion	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.1)

The staff's review of the steam and power conversion system and associated components followed one of several approaches. One approach, documented in Section 3.4.2.1 of this SER, involved the staff's review of the AMR results for components in the steam and power conversion system that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.4.2.2 of this SER, involved the staff's review of the AMR results for components in the steam and power conversion system that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.4.2.3 of this SER, involves the staff's review of the AMR results for components in the steam and power conversion system that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. The staff documents its review of AMPs that are credited to manage or monitor aging effects of the steam and power conversion system components in Section 3.0.3 of this SER.

3.4.2.1 Aging Management Evaluations That Are Consistent with the GALL Report, for Which No Further Evaluation Is Required

Summary of Technical Information in the Application

In Section 3.4.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the main steam, main feedwater, blowdown, and AFW system components:

- Bolting and Torquing Activities Program
- Flow-Accelerated Corrosion Program
- System Walkdown Program
- Water Chemistry Control Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- Preventive Maintenance Program
- Wall Thinning Monitoring Program

Staff Evaluation

In Tables 3.4.2-1 through 3.4.2-4 of the LRA, the applicant provided a summary of AMRs for the main feedwater, main steam, AFW, and blowdown system components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups are bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe the alignment of the information in the tables with the information in the GALL Report. The staff audited those AMRs with Notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP identified by the applicant is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the applicant took some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that it has reviewed and accepted the applicant's exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant could not find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component applies to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different, but consistent with the GALL Report for material, environment, and aging effect. In addition, the applicant took some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component applies to the component under review. The staff verified whether it reviewed and accepted the applicant's exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA and program bases documents, which are available at the applicant's engineering office. On the basis of its audit and review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant identified the applicable aging effects, and that these are appropriate for the combination of materials and environments listed.

On the basis of its audit and review, the staff concludes that the applicant demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion

The staff verified the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant demonstrated that it will adequately manage the effects of aging for these components so that their intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 Aging Management Evaluations That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application

In Section 3.4.2.2 of the LRA, the applicant provided further evaluation of aging management as recommended by the GALL Report for steam and power conversion systems. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling
- general corrosion
- loss of material due to general, pitting, crevice corrosion, and MIC

Staff Evaluation

For component groups evaluated in the GALL Report for which the applicant 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 further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.4.2.2 of the SRP-LR. The staff documents details of its audit and review in the audit and review report.

The GALL Report indicates that the applicant should perform further evaluation for the aging effects described in the following sections of this SER.

3.4.2.2.1 Cumulative Fatigue Damage

As stated in the SRP-LR, fatigue is a TLAA as defined in 10 CFR 54.3, and TLAAs must be evaluated in accordance 10 CFR 54.21(c)(1). Section 4.3 of this SER documents the staff's review of the applicant's evaluation of this TLAA. In performing this review, the staff followed the guidance in Section 4.3 of the SRP-LR.

3.4.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

Section 3.4.2.2.2 of the SRP-LR states that the management of the loss of material due to general, pitting, and crevice corrosion should be further evaluated for 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 the loss of material due to pitting and crevice corrosion for stainless steel tanks and heat exchanger/cooler tubes. The Water Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines of EPRI TR-102134, Revision 3, for the Secondary Water Chemistry Control Program to manage the effects of the loss of material due to general, pitting, or crevice corrosion. However, corrosion may occur at locations of stagnant flow conditions. Therefore, the applicant should verify the effectiveness of the Water Chemistry Control Program to ensure that corrosion does not occur. The GALL Report recommends further evaluating programs to manage the loss of material due to general, pitting, and crevice corrosion in order to verify the effectiveness of the Water Chemistry Control Program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion does not occur, and that the component's intended function will be maintained during the period of extended operation.

The GALL Report recommends GALL AMP XI.M32 for managing this aging effect.

In LRA Section 3.4.2.2.2, the applicant addressed the loss of material due to general, pitting, and crevice corrosion that could occur on the internal surfaces of piping and fittings, valve bodies and bonnets, piping manifolds, orifices, pump casings, strainer housings, tanks, tubes, tubesheets, channel heads, and shells (excluding the main steam system). General corrosion applies only to carbon steel components; pitting and crevice corrosion apply to both carbon and stainless steel components and to the cast iron strainer housings. In LRA Section 3.4.2.2.2, the applicant also addressed the GALL Report recommendation for further evaluation to verify the effectiveness of the Water Chemistry Control Program in managing the loss of material due to general, pitting, and crevice corrosion.

Regarding the components for which such an evaluation is required, the applicant credited the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program (CNP AMP B.1.40.1), with enhancements, to manage the loss of material by mitigating damage caused by corrosion. Section 3.0.3.2.15 of this SER evaluates CNP AMP B.1.40.1. Consistent with the GALL Report, the applicant supplemented its Primary and Secondary Water Chemistry Control Program with the Wall Thinning Monitoring Program (CNP AMP B.1.39) (AFW system components only) and the Water Chemistry Control—Chemistry One-Time Inspection Program (CNP AMP B.1.41) as the verification programs for the steam and power conversion system components.

Section 3.0.3.3.15 of this SER documents the staff's evaluation of CNP AMP B.1.39, which is a plant-specific program. The Water Chemistry Control—Chemistry One-Time Inspection Program is a new program that the applicant stated is consistent with GALL AMP XI.M32 but of a more limited scope. The staff documents its evaluation of CNP AMP B.1.41 in Section 3.0.3.3.17 of this SER.

3.4.2.2.3 Loss of Material due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

Section 3.4.2.2.3 of the SRP-LR states that the loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling could occur in carbon steel piping and fittings for untreated water from the backup water supply in the AFW system. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.4.2.2.3, the applicant addressed the loss of material in carbon steel piping and fittings for untreated water from the backup water supply in the AFW system.

In the LRA, the applicant stated that it addressed the portion of the lines from the ESW system to the AFW system that are exposed to untreated water as part of the ESW system (Item 3.3.1-17 in LRA Table 3.3.1). The staff finds that, with exceptions and enhancement, the Service Water System Reliability Program (CNP AMP B.1.29) is consistent with GALL AMP XI.M20 as discussed in Section 3.0.3.2.11 of this SER.

The applicant stated that CNP AMP B.1.40.1 and the System Testing Program (CNP AMP B.1.37), which manage the loss of material and fouling, supplement CNP AMP B.1.29. The staff evaluates these AMPs in Sections 3.0.3.2.15 and 3.0.3.3.13 of this SER, respectively. The staff finds that, although biofouling alone is not an aging effect, the AMPs manage the effects that may result from biofouling in carbon steel piping and fittings exposed to an internal environment of untreated water from the backup water supply in the ESW system.

The staff finds that the applicant demonstrated that it will adequately manage the effects of aging for the loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.4 General Corrosion

Section 3.4.2.2.4 of the SRP-LR states that the loss of material due to general corrosion could occur on the external surfaces of all carbon steel SCs, including closure boltings, exposed to operating temperatures less than 100 °C (212 °F). The GALL Report recommends further evaluation to ensure that this aging effect is adequately managed.

In LRA Section 3.4.2.2.4, the applicant stated that the loss of material due to general corrosion could occur on external surfaces of carbon steel SCs, including closure bolting, and the cast iron strainer housing in the AFW system. The strainer housing is included because industry experience has demonstrated that cast iron is subject to the same aging effects as carbon steel in this environment.

In the LRA, the applicant credited the System Walkdown Program (CNP AMP B.1.38), with enhancements, with managing the loss of material for the external surfaces of carbon steel SCs, including indoor and outdoor bolting, and the cast iron strainer housing. This is consistent with the GALL Report. The staff reviewed the applicant's enhanced System Walkdown Program and concludes that the program is acceptable. The staff documents its evaluation of this program in Section 3.0.3.3.14 of this SER.

The staff finds that the applicant demonstrated that it will adequately manage the effects of aging for loss of material due to general corrosion so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

Section 3.4.2.2.5 of the SRP-LR addresses the loss of material due to general corrosion (carbon steel only), pitting, crevice corrosion, and MIC which could occur in stainless steel and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the AFW system. The GALL Report recommends further evaluation to ensure the adequate management of these aging effects.

Section 3.4.2.2.5 of the SRP-LR also addresses the loss of material due to general corrosion, pitting, crevice corrosion, and MIC which could occur in underground piping and fittings and emergency CST in the AFW system and the underground CST in the condensate system. The Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material resulting from general corrosion, pitting, crevice corrosion, and MIC. The effectiveness of the Buried Piping and Tanks Inspection Program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that a loss of material is not occurring.

In LRA Section 3.4.2.2.5, the applicant addressed (1) the loss of material due to general corrosion, pitting, crevice corrosion, and MIC in carbon steel components exposed to lubricating oil in the AFW system and (2) the loss of material in underground piping and fittings and storage tanks for steam and power conversion systems. The components exposed to an internal environment of lubricating oil and subject to this aging effect are the AFW system carbon steel piping, pump casings, governor housing, heat exchanger shell, and sight glass housing.

The applicant stated that the Oil Analysis Program (CNP AMP B.1.23) manages the loss of material aging effect for carbon steel components exposed to an internal environment of lubricating oil in the AFW system. The staff finds that the applicant's oil analysis program adequately manages the effects of aging of loss of material for carbon steel components exposed to lubricating oil. The staff documents its evaluation of this AMP in Section 3.0.3.3.8 of this SER.

The staff confirmed that CNP has no buried components subject to an AMR in steam and power conversion systems.

The staff finds that the applicant demonstrated that it will adequately manage the effects of aging for the loss of material due to general, pitting, and crevice corrosion and MIC so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.6 Quality Assurance for Aging Management of Nonsafety related Components

Section 3.0.4 of this SER provides the staff's evaluation of the applicant's Quality Assurance Program.

Conclusion

On the basis of its review of 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 determines that the applicant adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in the SRP-LR. Because the applicant's AMR results are consistent with the GALL Report and the SRP-LR, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Staff Evaluation

The staff reviewed the AMR of the steam and power conversion system component, material, environment, AERM combinations that are not addressed in the GALL Report, as well as specific combinations addressed in the GALL Report within the scope of review. The AERM combinations not addressed in the GALL Report are addressed in notes F through J in LRA Tables 3.4.2-1 through 3.4.2-4. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for the identified component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that neither the identified component nor the material and environment combination is evaluated in the GALL Report.

Aging Effects

Tables 3.4.2-1 through 3.4.2-4 of the LRA list individual system components within the scope of license renewal and subject to AMR. The component types that do not rely on the GALL Report for AMR include piping, manifold (piping), valves, bolting, orifices, tubing, fittings, heat exchanger tubes, tanks, and sight glass.

For these component types, the applicant identified the following materials, environments, and AERMs:

- Stainless steel components exposed to an external air environment are subject to an aging effect of loss of mechanical closure integrity.

- Stainless steel components exposed to a steam or treated water (greater than 132°C (270 °)) environment are subject to aging effects of cracking fatigue and loss of material.

- Carbon steel components exposed to an external air environment are subject to aging effects of loss of mechanical closure integrity and loss of material.

- Carbon steel components exposed to steam (greater than 132 °C (270 °F)) or internal treated water are subject to the aging effect of loss of material.

- Copper alloys exposed to an environment of treated water or lubricating oil are subject to the aging effects of loss of material and fouling.

- Elastomers exposed to air or treated water environments are subject to the aging effects of change in material properties and cracking.

The staff reviewed the information in LRA Sections 2.3.4 and 3.4, including Tables 3.4.1 and 3.4.2-1 through 3.4.2-4. During its review, the staff determined that it required additional information to complete its review.

By letter dated May 26, 2004, the staff requested that the applicant provide additional information on the issues described in the system-specific RAIs. By letter dated June 30, 2004, the applicant responded to the RAIs. In the remainder of this section, the staff evaluates those RAIs and the applicant's responses which are applicable to several or all subsystems of the steam and power conversion system. The staff evaluates the subsystem-specific RAIs and responses in Sections 3.4.2.3.1 through 3.4.2.3.4 of this SER.

RAI 3.4-2

Table 3.4-1, Item 1, of the LRA identifies the applicant's aging management approach for cumulative fatigue damage of piping and fittings in the main feedwater line, the steamline, and AFW piping. In the "Discussion" column for this item, the LRA states, "See Section 4.3 [of the LRA]."

The applicant states in Section 4.3 of the LRA that, based on the screening criteria, it determined that the main feedwater, main steam, AFW, and blowdown systems exceed the screening criteria. The applicant evaluated the piping components that exceed the screening criteria for their potential to exceed 7000 thermal cycles in 60 years of plant operation. The applicant determined that none of the piping components in the steam and power conversion system will exceed 7000 cycles during the period of extended operation.

In RAI 3.4-2, the staff requested that the applicant provide the highest estimated number of thermal cycles, as well as the basis for derivation for each component type identified in LRA Tables 3.4.2-1 through -4 for which the applicant designated the TLAA of metal fatigue as the AMP.

The staff also requested that the applicant clarify whether, for certain components whose material or aging effect is not specified in the GALL Report (designated as 'F' and 'I' respectively in the notes), it performed the thermal cycle evaluation as described in Section 4.3.1.1.2 of the SRP-LR. If so, the staff asked the applicant to note whether its TLAA program is consistent with the SRP-LR. If not, the staff asked the applicant to explain any differences. In addition, the staff requested the applicant to address how it considered unanticipated transients and thermal stratification in its estimation.

In its response, the applicant stated the following:

> The evaluation of cracking by fatigue was identified as a TLAA for piping and valves in the main feedwater system, main steam system, auxiliary feedwater (AFW) system (*i.e.*, steam supply to the AFW pump and exhaust), and blowdown system. Mechanical components identified as susceptible to cracking by fatigue were designed in accordance with USAS B31.1.
>
> Main feedwater system and main steam system thermal cycles anticipated over 60 years correspond to heatup and cooldown cycles, for which CNP is restricted to 200 cycles. Therefore, main feedwater and main steam piping and valves will not experience 7,000 cycles during the period of extended operation.
>
> The steam supply to the AFW pump turbine and the turbine exhaust are exercised during AFW pump testing and during certain plant transients in which normal feedwater is unavailable. Significantly fewer than 7,000 equivalent full-temperature cycles of these components are expected during the period of extended operation, because the plant is restricted to 400 reactor trips and testing of the AFW pumps is performed on an 18-month cycle, in accordance with plant Technical Specifications.
>
> The steam generator blowdown system is placed in service primarily during startup to obtain the required water chemistry for normal operation. The plant is restricted to 200 heatups and cooldowns; therefore, this system will not exceed 200 equivalent full-temperature cycles. After startup, the steam generator blowdown system is used when corrections are required for secondary water chemistry. Sample lines that are connected to the steam generator blowdown system are in service continuously when blowdown is being exercised. Through the period of extended operation, the system is not expected to exceed 5,000 full-temperature equivalent cycles to correct secondary water chemistry during normal operation (assuming two secondary water chemistry corrections per week for 60 years, with an 80 percent capacity factor). Therefore, steam generator blowdown system will not experience 7,000 thermal cycles during the period of extended operation.
>
> The thermal cycle evaluations discussed in this RAI response pertain to those performed for USAS B 3.1.1 piping, as discussed in NUREG-1800, Section 4.3.1.1.2 , "ANSI B31.1."
>
> The thermal cycle assessment for USAS B3.1.1 piping, as described in NUREG-1800, Section 4.3.1.1.2, was performed for components that may operate at

temperatures that exceed the screening criteria provided in LRA Section 4.3.2. In addition to the 10 CFR 54.21(a) screening criteria, each mechanical system reviewed for the CNP IPA was also screened to identify potential metal fatigue TLAAs. This was accomplished by identifying non-Class 1 components that may operate at temperatures in excess of 104 °C (220 °F) for carbon steel, or 132 °C (270 °F) for austenitic stainless steel during normal or upset conditions. Fatigue evaluations of components that exceeded the screening criteria were identified as TLAAs for license renewal. These screening criteria are consistent with the screening criteria described in Section 4.3.2 of the St. Lucie Units 1 and 2 LRA.

The threshold value of 104 °C (220 °F) for thermal fatigue of carbon steel piping is based on an initial ambient temperature of 21 °C (70 °F) with a minimum temperature differential of 66 °C (150 °F). The threshold value of 132 °C (270 °F) for thermal fatigue of stainless steel piping is based on an initial ambient temperature of 21 °C (70 °F) with a minimum temperature differential of 93 °C (200 °F). The minimum temperature differentials are based on industry-sponsored investigations and evaluations of thermal fatigue in nuclear plant piping systems, as presented in EPRI TR-104534.

Thermal stratification in Class 1 portions of systems attached to the RCS is addressed in the I&M responses to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," (LRA References 4.3-11 through 4.3-15) as summarized in LRA Section 4.3.1.

UFSAR Section 4.1.4 describes cyclic load considerations. RCS components were designed to withstand the effects of cyclic loads resulting from reactor system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trips, and startup and shutdown operations. The number of thermal and loading cycles used for design purposes appears in UFSAR Table 4.1-10. To provide a high degree of integrity for the equipment in the RCS, the transient conditions selected for equipment fatigue evaluation were based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, normal and abnormal load transients, and accident conditions. To a large extent, the specific transient operating conditions considered for equipment fatigue analyses were based upon engineering judgment and experience. The transients chosen are representative of transients which prudently should be considered to occur during plant operation and which are sufficiently severe or may occur frequently to be of possible significance to component cyclic behavior.

With regard to the staff's concern related to unanticipated transients, the applicant stated that it did not account for unanticipated transients in its methodology, and that if they occur, they are identified and evaluated for impact on design thermal and loading cycles through the Corrective Action Program. The applicant monitors transients in critical Class 1 systems. The staff finds the applicant's response reasonable and acceptable because the applicant provided a satisfactory description of how thermal cycle evaluation is performed. The staff's concerns in RAI 3.4-2 are therefore resolved.

RAI 3.4-4

The Bolting and Torquing Activities Program (CNP AMP B.1.2), an existing plant-specific program, is credited with managing the loss of mechanical closure integrity. The program covers bolting in high-temperature systems and in applications subject to significant vibration. The staff notes that the GALL Report recommends GALL AMP XI.M 18 for monitoring the loss of material, cracking, and the loss of preload. In addition, accepted bolting integrity programs (such as EPRI TR-104213) recommend monitoring for the loss of preload as one of the parameters to be monitored/inspected. Monitoring for cracking of high-strength bolts (actual yield strength equal to or greater than 150 ksi) is also recommended.

As such, in RAI 3.4-4 the staff requested the applicant provide the following information:

A. Identify the areas of the Bolting Integrity Program at D. C. Cook which are consistent with the AMP XI.M.18 in the GALL report, and also those aspects in which it is different.

B. Discuss how the loss of preload aging effect would be managed by the Bolting and Torquing Activities AMP at D. C. Cook.

C. Discuss the inspections associated with the Bolting and Torquing Activities AMP at D. C. Cook which may be beyond the requirements of ASME Section XI.

D. Are there any high strength bolts included within the boundary of these systems (Engineered Safety Features and Steam & Power Conversion Systems)?

E. The occurrence of SCC in stainless steel bolts can depend on a combination of factors such as stainless steel grade, method of hardening (for example, strain, precipitation or age hardening) environment and stress levels. Discuss how these factors were taken into account to determine whether or not SCC is an applicable aging effect.

In its response the applicant stated the following:

A. The Bolting and Torquing Activities Program is an existing plant-specific program that was not compared to NUREG-1801, Section XI.M18.

The program described in NUREG-1801, Section XI.M18, covers all bolting within the scope of license renewal including safety-related bolting, bolting for nuclear steam supply system component supports, bolting for other pressure retaining components, and structural bolting. It includes periodic inspection of closure bolting for many aging effects, including loss of preload, cracking, and loss of material. Cracking of non-Class 1 stainless steel bolting is not an aging effect requiring management (see response to paragraph (e) below) and loss of material is managed by other programs identified in LRA Appendix B, as indicated in LRA Section 3.0 tables. Thus, the plant-specific Bolting and Torquing Activities Program, used only to manage loss of mechanical closure integrity, is not comparable to AMP XI.M18 of NUREG-1801.

In LRA Section B.1.2, the ten attributes of the Bolting and Torquing Activities Program were provided to allow for its assessment independent of NUREG-1801, Section XI.M18.

B. Loss of preload is managed by the Bolting and Torquing Activities Program by assuring that proper torque values are applied to bolted closures. With proper design of bolted closures, selection of appropriate torque values prevents loss of preload due to vibration or thermal cycles.

C. The Bolting and Torquing Activities Program is a preventive program. The associated inspections are a check of the bolt torque performed prior to joint assembly and verification of proper gasket compression after torquing.

D. CNP piping material specifications do not permit, nor have they historically permitted, high-strength bolting in non-Class 1 systems. Review of operating experience did not identify problems with cracking of high-strength bolting in air environments.

E. SCC occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. Proper lubricants and sealant compounds are used to minimize the potential for SCC. The Bolting and Torquing Activities Program provides for selection of appropriate lubricants and sealants to preclude introduction of significant contaminants.

In the aging management reviews, sufficient stress to initiate SCC was assumed if stainless steel bolting was subject to a corrosive environment. However, SCC very rarely occurs in austenitic stainless steels below 140 °F. Although SCC has been observed in stagnant, oxygenated borated water below 140 °F, all of these instances have identified a significant contaminant (halogens, specifically chlorides) affecting the failed components. Since stainless steel bolted closures are exposed to ambient temperature rather than high temperature process fluids, cracking of non-Class 1 stainless steel bolting is not an aging effect requiring management.

The staff discusses its evaluation of the applicant's response and resolution of the staff's concerns as part of the evaluation of RAI B.1.2-1 in Section 3.0.3.3.2 of this SER.

RAI 3.4-5

The applicant did not identify any aging effect for stainless steel tubes and tube fittings or valves (body only) in the reactor building environment. In RAI 3.4-5 the staff requested the applicant to justify this omission. If insignificant concentration of contaminants comprised part of the justification, the applicant was asked to provide the acceptance criterion and the verification/inspection activities on susceptible locations to justify the position.

The applicant stated the following in its response:

> The environment is maintained below 120 °F in the containment lower compartment and below 100 °F in the containment upper compartment. Stainless steel components are not susceptible to general corrosion in an air environment regardless of humidity level due to the inherent resistance of stainless steel to corrosion. Loss of material due to pitting or crevice corrosion requires a wetted environment (such as condensation (alternating wetting and drying which concentrates contaminants), pooling of liquid, or submergence) to be considered an aging effect requiring management. The containment environment does not contain significant moisture such that loss of material due to pitting and crevice corrosion is an aging effect requiring management for stainless steel components. Stainless steel components that are subject to a wetted environment are included in the LRA aging management review results tables with an environment other than air (*e.g.*, condensation, raw water, treated water). In addition, a review of plant operating experience identified no significant degradation of stainless steel components due to the containment environment.

The staff finds the applicant's response reasonable and acceptable because the applicant provided the specific environments to which the stainless steel components are exposed. The staff is satisfied that the loss of material due to pitting and crevice corrosion of stainless steel components under these conditions is not likely to occur.

RAI 3.4-10

Tables 3.4.2-1 through -4 of the LRA identify the loss of material and cracking as an aging effect for various stainless steel components in treated water and steam environments. The applicant credited the Water Chemistry Control Program to manage this aging effect. Stainless steels are susceptible to the loss of material in this type of environment, and the GALL Report recommends that, for the loss of material due to pitting and crevice corrosion, the effectiveness of the Water Chemistry Control Program should be verified to ensure that significant degradation is not occurring. In RAI 3.4-10, the staff requested the applicant to confirm that the One-Time Inspection Program discussed in Appendix B to the LRA will verify the effectiveness of the Water Chemistry Control Program for various stainless steel components in treated water and steam environments.

In its response, the applicant stated the following:

> NUREG-1801, Section XI.M2, "The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal.... Accordingly, in certain cases as identified in the GALL report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring.... As discussed in the GALL report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system." For steam and power conversion systems stainless steel components, the GALL Report only recommends augmentation of the Water Chemistry Control Program for the

condensate storage tank and heat exchanger tubes. Confirmation of the Water Chemistry Control Program's effectiveness is not recommended for other stainless steel components.

The Chemistry One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control Program, as described in LRA Section B.1.41. Inspections and examinations performed under this program will verify the effectiveness of the Water Chemistry Control Program in managing the aging effects of the loss of material and cracking for stainless steel in treated water and steam environments, as specified in the GALL Report.

The staff finds the applicant's response to RAI 3.4-10 reasonable and acceptable because the applicant clarified how the Chemistry One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control Program in managing the aging effects of the loss of material and cracking for stainless steel components in a treated water environment in accordance with the GALL Report.

3.4.2.3.1 Main Feedwater System

Staff Evaluation

The staff reviewed the AMR of the main feedwater system component, material, environment, AERM combinations not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.4.2-1. The staff also reviewed those combinations in Table 3.4.2-1 with notes A through E, which included emerging issues (*i.e.* ISG items). The staff verified that the applicant identified all applicable AERMs and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.4-1 of the LRA lists individual system components within the scope of license renewal that are subject to an AMR. The component types that do not rely on the GALL Report for AMR include bolting, piping, and valves.

For these component types, the applicant identified the materials, environments, and AERMs specified as follows:

- Carbon steel bolting in air (external) environments is subject to a loss of material and a loss of mechanical closure integrity.
- Stainless steel bolting in air (external) environments is subject to a loss of mechanical closure integrity.
- Stainless steel components in treated water (greater than 132 °C (270 °F)) (internal) environments are subject to a loss of material and to cracking.
- Stainless steel components in air (external) environments experience no aging effects.

During its review, the staff determined that it required additional information to complete its review.

RAI 3.4-2

Table 3.4-1, Item 1, of the LRA identifies the applicant's aging management approach for cumulative fatigue damage of piping and fittings in the main feedwater line, the steamline, and AFW piping. In the "Discussion" column for this item, the LRA states, "See Section 4.3 [of the LRA]."

The applicant stated in Section 4.3 of the LRA that, based on the screening criteria, it determined that some piping components in the main feedwater system exceed the screening criteria. The applicant evaluated the piping components that exceed the screening criteria for their potential to surpass 7000 thermal cycles in 60 years of plant operation. The applicant determined that none of the piping components in the steam and power conversion system will exceed 7000 cycles during the period of extended operation.

In RAI 3.4-2, the staff requested the applicant to provide the highest estimated number of thermal cycles, as well as the basis for derivation for each component type identified in Table 3.4.2-1 of the LRA. The staff evaluates the applicant's response in Section 3.4.2.3 of this SER. In its response to the RAI, the applicant stated that it did not account for unanticipated transients in its methodology, and that if they occur, they are identified and evaluated for impact on design thermal and loading cycles through the Corrective Action Program.

RAI 3.4-5

The applicant did not identify any aging effect for stainless steel tube and tube fittings or valves (body only) in the reactor building environment. In RAI 3.4-5, the staff asked the applicant to justify this omission. If insignificant concentration of contaminants comprised part of the justification, the applicant was asked to provide the acceptance criterion and the verification/inspection activities on susceptible locations to justify the position. Section 3.4.2.3 of this SER evaluates the applicant's response.

The staff finds the applicant's response reasonable and acceptable because the applicant provided the specific environments to which the stainless steel components are exposed. The staff is satisfied that loss of material due to pitting and crevice corrosion of stainless steel components under these conditions is not likely to occur.

RAI 3.4-10

Table 3.4.2-1 of the LRA identifies the loss of material and cracking as an aging effect for various stainless steel components in treated water and steam environments. The applicant credited the Water Chemistry Control Program to manage this aging effect. Stainless steels are susceptible to the loss of material in this type of environment, and the GALL Report recommends that, for the loss of material due to pitting and crevice corrosion, the effectiveness of the Water Chemistry Control Program should be verified to ensure that significant degradation is not occurring. In RAI 3.4-10, the staff requested the applicant to confirm that the One-Time Inspection Program discussed in Appendix B to the LRA will verify the effectiveness of the Water Chemistry Control Program for various stainless steel components in treated water and steam environments.

The staff discusses the applicant's response in Section 3.4.2.3 of this SER. The staff finds the applicant's response reasonable and acceptable because the applicant clarified how the Chemistry One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control Program in managing the aging effects of the loss of material and cracking for stainless steel components in a treated water environment, in accordance with the GALL Report.

On the basis of its review of the information in the LRA and additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects of the steam and power conversion system component types that are not addressed in the GALL Report, as well as the specific component types that are within the scope of review, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the steam and power conversion system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.4.2-2 of the LRA identifies the following AMPs for managing the aging effects described above for the main feedwater system:

- Bolting and Torquing Activities Program (B.1.2)
- Flow-Accelerated Corrosion Program (B.1.12)
- System Walkdown Program (B.1.38)
- Water Chemistry Control Program (B.1.40)

The staff reviews these AMPs in detail in Sections 3.0.3.3.2, 3.0.3.1, 3.0.3.3.14, and 3.0.3.3.16 of this SER, respectively.

In the LRA, the applicant stated that it did not identify any aging effects for stainless steel components exposed to air, including piping and valve component types. The GALL Report does not identify air as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoor, or air-conditioned enclosure or room). Wrought austenitic stainless steels and CASS are not susceptible to significant general corrosion that would affect the intended functions of components. Therefore, the staff concludes that there are no AERMs for metal in a dry air environment.

In the LRA, the applicant stated that it manages cracking and the loss of material for stainless steel components exposed to an internal environment of treated water greater than 132 °C (270 °F) using the Water Chemistry Control—Primary and Secondary Water Program, with enhancements. The staff documents its evaluation of this AMP in Section 3.0.3.2.15 of this SER. The GALL Report, Section VIII.D.1.1-c, recommends that the AMP be augmented by verifying the effectiveness of the Water Chemistry Control Program. Table 3.4.1, Item 3.4.1-2, of the LRA and LRA Section 3.4.2.2.2 both identify the Wall Thinning Monitoring Program as the verification program that will supplement the Water Chemistry Control Programs.

In the LRA, the applicant stated that the Water Chemistry Control—Chemistry One-Time Inspection Program is a new program that is consistent with GALL AMP XI.M32, but of a more limited scope. The staff documents its evaluation of this AMP in Section 3.0.3.3.17 of this SER.

On the basis of its review of the information provided in the LRA, the staff finds that the applicant identified the appropriate AMPs for managing the aging effects of the main feedwater system component types not addressed by the GALL Report. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the main feedwater system components that are not addressed by the GALL Report, so that it will maintain the intended functions 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 the UFSAR Supplement adequately describes the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.4.2.3.2 Main Steam System

Staff Evaluation

The staff reviewed the AMR of the main steam system component, material, environment, AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.4.2-1. The staff also reviewed those combinations in Table 3.4.2-2 with notes A through E, which include emerging issues (*i.e.* ISG items). The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.4-2 of the LRA lists individual system components within the scope of license renewal that are subject to an AMR. The component types that do not rely on the GALL Report for AMR include bolting, manifold piping, orifices, piping, tubing, and valves.

For these component types, the applicant identified the materials, environments, and AERMs specified as follows:

- Carbon steel bolting in air (external) environments is subject to a loss of material and a loss of mechanical closure integrity.
- Stainless steel bolting in air (external) environments is subject to a loss of mechanical closure integrity.
- Stainless steel components in steam (greater than 132 °C (270 °F) (internal) and treated water (greater than 132 °C (270 °F) (internal) environments are subject to a loss of material and cracking.
- Stainless steel components in air (external) environments experience no aging effects.

During its review, the staff determined that it required additional information to complete its evaluation.

Table 3.4-1, Item 1, of the LRA identifies the applicant's aging management approach for cumulative fatigue damage of piping and fittings in the main feedwater line, the steamline, and AFW piping. In the "Discussion" column for this item, the LRA states, "See Section 4.3 [of the LRA]."

The applicant stated in Section 4.3 of the LRA that, based on the screening criteria, it determined that some piping components in the main steam system exceed the screening criteria. The applicant evaluated the piping components that exceed the screening criteria for their potential to surpass 7000 thermal cycles in 60 years of plant operation. Main steam system thermal cycles anticipated over 60 years correspond to heatup and cooldown cycles, for which CNP is restricted to 200 cycles. Therefore, main steam piping and valves will not experience 7000 cycles during the period of extended operation.

RAI 3.4-10

Table 3.4.2-2 of the LRA identifies the loss of material and cracking as an aging effect for various stainless steel components in treated water and steam environments. The applicant credited the Water Chemistry Control Program to manage this aging effect. Stainless steels are susceptible to the loss of material in this type of environment, and the GALL Report recommends that, for the loss of material due to pitting and crevice corrosion, the effectiveness of the Water Chemistry Control Program should be verified to ensure that significant degradation is not occurring. In RAI 3.4-10, the staff requested the applicant to confirm that the One-Time Inspection Program discussed in Appendix B to the LRA will verify the effectiveness of the Water Chemistry Control Program for various stainless steel components in treated water and steam environments.

Section 3.4.2.3 of this SER discusses the applicant's response and the resolution of the staff's concerns. The staff finds the applicant's response reasonable and acceptable because the applicant clarified how the Chemistry One-Time Inspection Program will verify the effectiveness of the Chemistry Control Program in managing the aging effects of the loss of material and cracking for stainless steel components in a treated water environment, in accordance with the GALL Report.

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 3.4-10, the staff finds that the applicant has identified the appropriate AMPs for managing the aging effects of the main steam system component types not addressed by the GALL Report. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Aging Management Programs

The staff reviewed Table 3.4.2-2 of the LRA, which summarized the results of AMR evaluations in the SRP-LR for the main steam system component groups.

The applicant stated in the LRA that it identified no aging effects for stainless steel components exposed to air, including manifold (piping), piping, tubing, and valve component types. The GALL Report does not identify air as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoor, or air-conditioned enclosure or room). Wrought austenitic stainless steels and CASS are not susceptible to significant general corrosion that would affect the intended function of components. Therefore, the staff concludes that there are no AERMs for metal in a dry air environment.

In the LRA, the applicant stated that it uses the Water Chemistry Control—Primary and Secondary Water Program, with enhancements, to manage cracking and the loss of material for stainless steel manifold, piping, tubing, and valves exposed to internal environments of treated water greater than 132 °C (270 °F) and steam greater than 132 °C (270 °F). The staff documents its evaluation of this AMP in Section 3.0.3.2.15 of this SER. The staff noted that the GALL Report does not discuss similar component, material, and environment combinations. However, the aging effects of cracking and loss of material for the main steam system stainless steel components exposed to internal environments of treated water greater than 132 °C (270 °F) and steam greater than 132 °C (270 °F) are consistent with industry operating experience. The staff finds that the appropriate aging effects were identified and are adequately managed and, therefore, are acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, as well as the AMPs credited for managing the aging effects, for the main steam system components that are not addressed by the GALL Report, 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describes the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.4.2.3.3 Auxiliary Feedwater System

Staff Evaluation

The staff reviewed the AMR of the AFW system component, material, environment, and AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.4.2-3, except for those for which past precedents exist. The staff also reviewed those combinations in Table 3.4.2-3 with notes A through E, for which emerging issues were identified. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.4-3 of the LRA lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include bolting, fittings, heat exchanger (tubes), orifices, piping, manifold piping, sight glass, tanks, tubing, turbine casing and valves.

For these component types, the applicant identified the materials, environments, and AERMs specified as follows:

- Carbon steel bolting in air (external) environments is subject to a loss of material and a loss of mechanical closure integrity.
- Carbon steel components in steam (greater than 132 °C (270 °F)) (internal) and treated water (internal) environments are subject to a loss of material and cracking - fatigue.
- Stainless steel bolting in air (external) environments is subject to a loss of mechanical closure integrity.
- Stainless steel components in a steam (greater than 132 °C (270 °F)) (internal) environment are subject to a loss of material, cracking - fatigue, and cracking.
- Stainless steel components in a treated water (internal) environment are subject to a loss of material.
- Stainless steel components in air (internal and external), outdoor air (external), and concrete (external) environments experience no aging effects.
- Copper alloy components in lubricating oil (internal) and treated water (internal) environments are subject to fouling and a loss of material.
- Copper alloy components in air (external) and outdoor air (external) environments experience no aging effects.
- Elastomer components in air (external) and treated water (internal) environments are subject to cracking and change in material properties.

- Glass components in air (external) and lubricating oil (internal) environments experience no aging effects.

During its review, the staff determined that it required additional information to complete its evaluation.

RAI 3.4-1

Table 3.4.2-3 of the LRA identifies no aging effects for copper alloy in an outside environment in the AFW system. The outside environment is generally defined as follows:

> An environment where components are exposed to direct sunlight, precipitation, and freezing conditions. The outside environment also conservatively includes components located in sheltered areas where the component is beneath some type of roof structure or outdoor enclosure (such as a valve box) but is otherwise open to the ambient environment.

The GALL Report does not identify copper alloy components for this environment. However, the GALL Report recommends aging management for the loss of material due to general corrosion on the external surfaces of carbon (alloy) steel components exposed to operating temperatures less than 100 °C (212 °F). Such corrosion may result from air, moisture, or humidity. In RAI 3.4-1, the staff requested the applicant to provide a program to manage corrosion on the external surface of copper alloy components in an outside environment, or to justify not managing this aging effect.

In its response, the applicant stated the following:

> The copper alloy components exposed to outdoor air in LRA Table 3.4.2-3 are instrument tubing, fittings, and valves off the condensate storage tank. Unlike carbon steel materials which are not corrosion resistant, copper alloys are highly resistant to general corrosion in an external air environment. These copper alloy components are sheltered (either located inside or insulated) and are not directly exposed to the atmosphere. These components are not expected to be exposed to significant moisture or contaminants (such as those deposited as a result of alternating wetting and drying); therefore, loss of material due to pitting, crevice corrosion, or selective leaching is not an aging effect requiring management.

The staff finds the applicant's response satisfactory and acceptable because it provides an adequate justification for not managing the aging effect of corrosion on the external surface of copper alloy components.

RAI 3.4-3

The applicant stated in Table 3.4.2-3 of the LRA that stainless steel tanks in an external concrete environment have no AERms and that the GALL Report contains no AMP for this component and material in such an environment. In RAI 3.4-3, the staff requested the applicant identify the specific tanks in the AFW system and discuss how it assures the integrity of welds and wall thickness in inaccessible locations in the tank, including method and frequency of inspections, as well as the basis for this approach.

The applicant identified the stainless steel tank exposed to a concrete (external) environment as the CST (TK-32), which is depicted on license renewal drawings LRA-1-5106A and LRA-2-5106A. The applicant also stated the following:

> The tank base is in contact with the concrete pad. The concrete pads are constructed in accordance with ACI 318-63, which results in high-quality concrete free of contamination. Therefore, loss of material is not an aging effect requiring management due to the inherent corrosion resistance of stainless steel, the high alkalinity of concrete, and the lack of contamination. Since there are no aging effects requiring management for this external stainless steel surface, periodic thickness measurements are not required.

The staff finds the applicant's response reasonable and acceptable because it adequately justifies that AERMs are not likely to occur at the bottom of the stainless steel tank.

RAI 3.4-6

The applicant identified no applicable aging effect for carbon steel components in an embedded environment. If this environment involves concrete, corrosion of carbon steel components embedded in concrete through carbonation is a commonly known degradation process. In RAI 3.4-6 the staff requested that the applicant explain this omission. In its response the applicant stated the following:

> During scoping and screening of mechanical portions of the steam and power conversion systems, no carbon steel components in an embedded environment were identified as subject to aging management review. LRA Table 3.4.1, Items 3.4.1-11 and 3.4.1-12, document this result.

Because the steam and power conversion system does not include any no carbon steel components in an embedded environment, the staff considers the RAI issue resolved.

RAI 3.4-7

The applicant stated in Table 3.4.2-3 of the LRA that it will use the Oil Analysis and Water Chemistry Control Programs to manage fouling in heat exchangers with copper alloy tubes in lubricating-oil and treated-water environments to assure the heat transfer capability. In RAI 3.4-7, the staff requested the applicant to explain how these two AMPs will manage fouling and assure adequate heat transfer. The staff also requested that the applicant address whether it would perform any cleaning, visual inspections, and thermal performance testing, including the frequency of such inspections and tests and the basis for this approach.

In its response, the applicant stated the following:

> The heat exchangers in LRA Table 3.4.2-3 are the turbine-driven AFW pump turbine bearing lube oil cooler (HE-70) and governor oil cooler (HE-71), which are depicted on license renewal drawings LRA-1-5106A at locations L3 and M2 and LRA-2-5106A at locations D2 and E2. As part of the Primary and Secondary Water Chemistry Control Program, water quality and level of contaminants in the secondary plant water (*i.e.*, AFW) are monitored and maintained within the

specifications of EPRI TR-102134, Revision 5. The Oil Analysis Program monitors and controls abnormal levels of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to fouling. By maintaining proper water chemistry and oil quality, contaminants within these fluids are minimized such that fouling that could result in the loss of heat transfer function is prevented. Visual inspections and thermal performance testing are not included in these programs. However, the Chemistry One-Time Inspection Program, as described in LRA Section B.1.41, includes inspections to verify effectiveness of the chemistry control programs. Based on plant operating experience, there is reasonable assurance that the Oil Analysis Program and the Primary and Secondary Water Chemistry Control Program will continue to adequately manage fouling associated with components exposed to lubricating oil and secondary plant water so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation.

The staff finds the applicant's response reasonable and acceptable because the applicant provided a satisfactory explanation of how it will manage the aging effect of fouling in the copper alloy tubes of the heat exchangers. Therefore, the staff considers the issues related to this RAI to be resolved.

RAI 3.4-8

Table 3.4.2-3 of the LRA identifies loss of material and fouling for copper alloy heat exchanger tubes in a treated water environment. The applicant credited the Water Chemistry Control Program to manage this aging effect. The GALL Report does not identify this material for this component, but it recommends the Water Chemistry Control Program and a one-time inspection to manage the loss of material for carbon/alloy steel components in a treated water environment. Table 3.4.2-3 of the LRA does not identify a one-time inspection to verify the effectiveness of the Water Chemistry Control Program. However, Appendix B to the LRA (Section B.1.41) discusses a new plant-specific one-time inspection program. In RAI 3.4-8, the staff requested the applicant to clarify that this program will include inspections and examinations to verify the effectiveness of the Water Chemistry Control Program to manage the loss of material and fouling for copper alloy heat exchanger tubes in a treated water environment.

In its response, the applicant stated the following:

> The heat exchangers in LRA Table 3.4.2-3 are the turbine-driven AFW pump turbine bearing lube oil cooler (HE-70) and the governor oil cooler (HE-71), which are depicted on license renewal drawings LRA-1-5106A at locations L3 and M2 and LRA-2-5106A at locations D2 and E2. Effectiveness of the water chemistry control programs will be verified by the Chemistry One-Time Inspection Program as described in LRA Section B.1.41. Inspections and examinations performed under the Chemistry One-Time Inspection Program will verify the effectiveness of the Primary and Secondary Water Chemistry Control Program in managing loss of material and fouling for copper alloy heat exchanger tubes in a treated water environment.

The staff finds the applicant's response reasonable and acceptable because the applicant confirmed that the Chemistry One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control Program in managing the loss of material and fouling for copper alloy tubes in a treated water environment. Therefore, the staff considers the issues related to this RAI to be resolved.

RAI 3.4-9

Table 3.4.2-3 of the LRA states that the Preventive Maintenance Program will manage the change in material properties and cracking of elastomeric material of tanks in a treated water environment. However, the Preventive Maintenance Program in Appendix B to the LRA does not discuss the aging management of pressure-retaining elastomeric tanks in a treated water environment. In RAI 3.4-9 the staff requested the applicant describe how it will manage the change in material properties and cracking in tanks, including its inspection methods for inaccessible locations and the frequency of inspections, as well as its acceptance criteria and the basis thereof.

In its response to RAI 3.4-9, the applicant stated the following:

> The elastomer material identified for the component type "Tank" listing in LRA Table 3.4.2-3 refers to the CST floating head seals. The floating head seals and associated support posts were included in the aging management review because the failure of these seals could cause flow blockage. As stated in LRA Section B.1.25, the Preventive Maintenance Program will be enhanced prior to the period of extended operation to include visual inspection and replacement, as needed, of these elastomer floating head seals. Inaccessible locations will be exposed to the same environments (*i.e.*, air and treated water) as the accessible locations that will be subject to the visual inspections; therefore, the condition of the accessible surfaces of the elastomer seal would be representative of the inaccessible locations. The seal inspection frequency will be established based on industry and plant-specific operating experience and manufacturer's recommendations. Acceptance criteria will be defined by specific inspection and testing procedures based on industry and plant-specific operating experience and manufacturer's recommendations.

The staff finds the applicant's response reasonable and acceptable because the applicant provided a satisfactory description of how it will manage the aging effects of change in material properties and cracking for elastomeric materials in a treated water environment. Therefore, the staff considers the issues related to this RAI to be resolved.

On the basis of its review of the information in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects of the AFW system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the AFW system.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.4.2-3 of the LRA identifies the following AMPs for managing the aging effects described above for the AFW system:

- Bolting and Torquing Activities Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- Preventive Maintenance Program
- System Walkdown Program
- Water Chemistry Control Program
- Wall Thinning Monitoring Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.3.2, 3.0.3.3.5, 3.0.3.3.8, 3.0.3.3.10, 3.0.3.3.14, 3.0.3.2.15 and 3.0.3.3.15 of this SER, respectively.

The applicant stated in the LRA that it identified no aging effects for the copper alloy fittings, manifold, tubing, and valves exposed to air, as well as for fittings, tubing, and valves in outdoor air. The applicant identified no aging effects for stainless steel fittings, manifold, orifices, tubing, and valves exposed to air, as well as for fittings, piping, tanks, tubing, and valves in outdoor air. The GALL Report does not identify air as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoors, or in an air-conditioned enclosure or room). Wrought austenitic stainless steels are not susceptible to significant general corrosion that would affect the intended function of the components. Therefore, the staff concludes that metal in a dry air environment has no AERMs.

In the LRA, the applicant stated that it manages cracking and the loss of material for stainless steel fittings, tubing, and valves exposed to an internal environment of steam greater than 132 °C (270 °F) using the Water Chemistry Control - Primary and Secondary Water Chemistry Control Program, with enhancements. The staff documents its evaluation of this AMP in Section 3.0.3.2.15 of this SER. The GALL Report does not discuss similar component, material, and environment combinations. The aging effects of cracking and the loss of material for the AFW system's stainless steel components exposed to an internal environment of steam greater than 132 °C (270 °F) are consistent with industry operating experience. The staff finds that the applicant identified and adequately manages the appropriate aging effects. The staff finds this to be acceptable.

In the LRA, the applicant stated that it manages fouling and the loss of material for copper alloy heat exchanger tubes exposed to an external environment of lubricating oil using the Oil analysis Program. The staff documents its evaluation of this program in Section 3.0.3.3.8 of this SER. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that the applicant's Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates), the staff finds that this program adequately manages cracking and the loss of material for components exposed to lubricating oil.

In the LRA, the applicant stated that the sight glass component type (glass) in an external environment of air or an internal environment of lubricating oil has no aging effects. The GALL Report does not discuss similar component, material, and environment combinations. On the basis that no aging effects require management for these components, the staff finds the absence of an AMP for glass to be acceptable.

In the LRA, the applicant stated that it manages cracking and change in material properties of tank elastomer exposed to an external environment of air and an internal environment of treated water using the Preventive Maintenance Program (CNP AMP B.1.25), with enhancements. The applicant stated that the program enhancement will rely upon visual inspection to detect cracking and change in material properties of the AFW system elastomer CST's floating head seals. The staff documents its evaluation of this AMP in Section 3.0.3.3.10 of this SER.

The GALL Report does not discuss similar component, material, and environment combinations. The staff found documentation only of visual inspection, which is an acceptable method for detecting cracking. The staff asked the applicant to clarify how it intends to detect changes in material properties. The staff asked the applicant, in RAI 3.4-9, to describe how it will manage the change in material properties and cracking of elastomeric materials in tanks, including its inspection methods for inaccessible locations, frequency of inspections, acceptance criteria, and the basis for its approach. The staff evaluated and accepted the applicant's response to this RAI as described above.

In the LRA, the applicant stated that it manages the loss of material from copper alloy valves in treated water using the Water Chemistry Control Program. On the basis that this is consistent with the management of similar items identified in the GALL Report, the staff finds it 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 applicant has identified appropriate AMPs for managing the aging effects of the AFW system component types not addressed by the GALL Report. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, as well as the AMPs credited with managing the aging effects, for the AFW system components that are not addressed by the GALL Report, 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 applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement adequately describe the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.4.2.3.4 Blowdown System

Staff Evaluation

The staff reviewed the AMR of the blowdown system component, material, environment, and AERM combinations that are not addressed in the GALL Report. These combinations use notes F through J in LRA Table 3.4.2-4, except for those for which past precedents exist. The staff also reviewed those combinations in Table 3.4.2-4 with notes A through E, for which emerging issues were identified. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs to manage the AERMs. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that they adequately describe the AMPs.

Aging Effects

Table 2.3.4-4 of the LRA lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR include bolting, orifices, piping, tubing, and valves.

For these component types, the applicant identified the materials, environments, and AERMs specified as follows:

- Carbon steel components in air (external) environments are subject to a loss of material and a loss of mechanical closure integrity.
- Carbon steel components subjected to treated water (greater than 132 °C (270 °F)) (internal) environments are subject to cracking fatigue.
- Stainless steel bolting in air (external) environments is subject to a loss of mechanical closure integrity.
- Stainless steel components in treated water (greater than 132 ° (270 °F)) (internal) environment are subject to a loss of material and cracking.

During its review, the staff determined that it required additional information to complete its evaluation. The following provides the staff's evaluation and resolution of its concerns.

RAI 3.4-2

The applicant determined that none of the piping components in the steam and power conversion system will exceed 7000 cycles during the period of extended operation. In RAI 3.4-2, the staff requested the applicant provide the highest estimated number of thermal cycles, as well as the basis for derivation for each component type identified in Table 3.2.4-4 of the LRA for the blowdown systems.

In its response to the RAI, the applicant stated that the steam generator blowdown (SGBD) system is placed in service primarily during startup to obtain the required water chemistry for normal operation. The plant is restricted to 200 heatups and cooldowns; therefore, this system will not exceed 200 equivalent full-temperature cycles. After startup, the SGBD system is used when corrections are required for secondary water chemistry. Sample lines connected to the SGBD system are in service continuously when blowdown is being exercised. For the period of extended operation, the system is not expected to exceed 5000 full-temperature equivalent cycles to correct secondary water chemistry during normal operation (assuming two secondary water chemistry corrections per week for 60 years, with an 80-percent capacity factor). Therefore, the SGBD system will not experience 7000 thermal cycles during the period of extended operation. The staff finds the applicant's response reasonable and acceptable because it clarifies the basis for derivation of the thermal cycles for the blowdown system. Section 3.4.2.3 of this SER discusses other staff concerns brought forth in RAI 3.4-2.

Table 3.4.2-4 of the LRA identifies the loss of material and cracking as aging effects for various stainless steel components in treated water and steam environments. In RAI 3.4-10 the staff requested the applicant confirm that the One-Time Inspection Program discussed in Appendix B to the LRA will verify the effectiveness of the Water Chemistry Control Program for various stainless steel components in treated water and steam environments.

In its response the applicant stated, "For steam and power conversion systems stainless steel components, NUREG-1801 only recommends augmentation of the water chemistry program for the CST and heat exchanger tubes."

The staff finds the applicant's response reasonable and acceptable because the applicant clarified how the Chemistry One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control Program in managing the aging effects of the loss of material and cracking for stainless steel components in a treated water environment, which is in accordance with the GALL Report. The staff discusses other concerns brought up in RAI 3.4-10 in Section 3.4.2.3 of this SER.

Aging Management Programs

After evaluating the applicant's identification of aging effects for each of the above component types, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR Supplement adequately describes the program.

Table 3.4.2-4 of the LRA identifies the following AMPs for managing the aging effects described above for the blowdown system:

- Bolting and Torquing Activities Program
- System Walkdown Program
- Water Chemistry Control Program
- Flow-Accelerated Corrosion Program
- System Testing Program

The staff's detailed review of these AMPs appears in Sections 3.0.3.3.2, 3.0.3.3.14, 3.0.3.2.15, 3.0.3.1 and 3.0.3.3.13 of this SER, respectively.

The applicant stated that it did not identify any aging effects for stainless steel components exposed to air, including orifices, piping, tubing, and valve component types. The GALL Report does not identify air as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoor, or air-conditioned enclosure or room). Therefore, the staff concludes that metal in a dry air environment has no AERMs.

In the LRA, the applicant stated that it manages cracking and the loss of material for stainless steel orifices, piping, tubing, and valve exposed to an internal environment of treated water greater than 132 °C (270 °F) using the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program, with enhancements. The staff documents its evaluation of this AMP in Section 3.0.3.2.15 of this SER. The GALL Report does not discuss similar component, material, and environment combinations. The aging effects of cracking and loss of material for the blowdown system's stainless steel components exposed to internal environments of treated water greater than 132 °C (270 °F) are consistent with industry operating experience. The staff finds that the applicant identified and adequately manages the appropriate aging effects. The staff finds this 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 RAIs, the staff finds that the applicant has identified the appropriate AMPs for managing the aging effects of the blowdown system component types not addressed by the GALL Report. In addition, the staff finds the program descriptions in the UFSAR Supplement acceptable.

<u>Conclusion</u>

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, as well as the AMPs credited with managing the aging effects, for the blowdown system components that are not addressed by the GALL Report, so that the intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.4.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the main feedwater, main steam, AFW, and blowdown system components that are within the scope of license renewal and subject to an AMR so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Structures and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the structures and component supports and commodity groups associated with the following structures:

- containment
- auxiliary building
- turbine building and screenhouse
- yard structures
- structural commodities

3.5.1 Summary of Technical Information in the Application

In Section 3.5 of the LRA, the applicant provided the results of the AMR of the structures and component supports components and component types listed in Tables 2.4-1 through 2.4-5 of the LRA. The applicant also listed the materials, environments, AERMs, and AMPs associated with each structure and component support type.

In Table 3.5.1, "Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801," of the LRA, the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the structures and component supports. In Section 3.5.2.2 of the LRA, the applicant provided information concerning Table 3.5.1 components for which the GALL Report recommends further evaluation.

3.5.2 Staff Evaluation

The staff reviewed Section 3.5 of the LRA to understand the applicant's review process and to determine whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the structures and component supports that are within the scope of license renewal and subject to an AMR, so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL AMRs. Section 3.5.2.1 of this SER summarizes the staff's audit and review findings .

The staff also audited those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations were consistent with the acceptance criteria in Section 3.5.3.2 of the SRP-LR. Section 3.5.2.2 of this SER summarizes the staff's audit and review findings.

The staff conducted a technical review of the remaining AMRs that are not consistent with the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff documents its review findings in Section 3.5.2.3 of this SER.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they adequately describe the programs credited with managing or monitoring aging for the structures and component supports.

Table 3.5-1 below summarizes the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Structures and Component Supports Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves, penetration bellows, and dissimilar metal welds (Item Number 3.5.1-1)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation (See Sections 3.5.2.2.1 and 4.6)
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-2)	Crack initiation and growth due to SCC	Containment ISI and containment leak rate test	Containment Leakage Rate Testing Program (B.1.8); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.15)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.1)
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-3)	Loss of material due to corrosion	Containment ISI and containment leak rate test	Containment Leakage Rate Testing Program (B.1.8); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.15)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1-4)	Loss of material due to corrosion	Containment ISI and containment leak rate test	Containment Leakage Rate Testing Program (B.1.8); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.15)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Personnel airlock and equipment hatch (Item Number 3.5.1-5)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanisms	Containment leak rate test and plant technical specifications	Containment Leakage Rate Testing Program (B.1.8); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.15); CNP Technical Specification	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Seals, gaskets, and moisture barriers (Item Number 3.5.1-6)	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 Leakage Rate Testing Program (B.1.8); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.15)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Concrete elements—foundation, dome, and wall (Item Number 3.5.1-7)	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	Inservice Inspection—ASME Section XI, Subsection IWL Program (B.1.17); Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.1)
Concrete elements—foundation (Item Number 3.5.1-8)	Cracks, distortion, and increases in component stress level due to settlement	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.1)
Concrete elements—foundation (Item Number 3.5.1-9)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32); Inservice Inspection—ASME Section XI, Subsection IWL Program (B.1.17)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.1)
Concrete elements—foundation, dome, and wall (Item Number 3.5.1-10)	Reduction of strength and modulus due to elevated temperature	Plant specific	Structures Monitoring—Structures Monitoring Program (B.1.32); Inservice Inspection—ASME Section XI, Subsection IWL Program (B.1.17)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Prestressed containment—tendons and anchorage components (Item Number 3.5.1-11)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA evaluated in accordance with 10 CFR 54.21(c)	Not Applicable	Consistent with GALL, which recommends further evaluation (See Sections 3.5.2.2.1 and 4.5)
Steel elements—liner plate and containment shell (Item Number 3.5.1-12)	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI and containment leak rate test	Structures Monitoring—Structures Monitoring Program (B.1.32); Inservice Inspection—ASME Section XI, Subsection IWE Program (B.1.17)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.1)
Steel elements—protected by coating (Item Number 3.5.1-14)	Loss of material due to corrosion in accessible areas only	Protective coating monitoring and maintenance	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Prestressed containment—tendons and anchorage components (Item Number 3.5.1-15)	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI	Not Applicable	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Concrete elements—foundation, dome, and wall (Item Number 3.5.1-16)	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	Structures Monitoring—Structures Monitoring Program (B.1.32); Inservice Inspection—ASME Section XI, Subsection IWL Program (B.1.17)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.2)
All groups except Group 6—accessible interior/exterior concrete steel components (Item Number 3.5.1-20)	All types of aging effects	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups 1–3, 5, and 7–9—inaccessible concrete components, such as exterior walls below grade and foundation (Item Number 3.5.1-21)	Aging of inaccessible concrete areas due to aggressive chemical attack; corrosion of embedded steel	Plant specific	Not Applicable	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.2)
Group 6—all accessible/ inaccessible concrete, steel, and earthen components (Item Number 3.5.1-22)	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of water-control structures or FERC/U.S. Army Corp of Engineers dam inspection and maintenance	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Group 5—liners (Item Number 3.5.1-23)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Water chemistry and monitoring spent fuel pool water level	System Testing Program (B.1.37)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1–3, 5, and 6—all masonry block walls (Item Number 3.5.1-24)	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry wall	Structures Monitoring—Masonry Wall Program (B.1.36)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1–3, 5, and 7–9—foundation (Item Number 3.5.1-25)	Cracks, distortion, and increases in component stress level due to settlement	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.1)
Groups 1–3 and 5–9—foundation (Item Number 3.5.1-26)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.1)
Groups 1–5—concrete (Item Number 3.5.1-27)	Reduction of strength and modulus due to elevated temperature	Plant specific	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups 7–8—liners (Item Number 3.5.1-28)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Plant specific	Not Applicable	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.2)
All groups' support members—anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc. (Item Number 3.5.1-29)	Aging of component supports	Structures monitoring	Structures Monitoring—Structures Monitoring Program (B.1.32)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.2.3)
Group B1.1, B1.2, and B1.3 support members—anchor bolts and welds (Item Number 3.5.1-30)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation (See Sections 3.5.2.2.3 and 4.3)
All groups' support members—anchor bolts and welds (Item Number 3.5.1-31)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Group B1.1, B1.2, and B1.3 support members—anchor bolts, welds, spring hangers, guides, stops, and vibration isolators (Item Number 3.5.1-32)	Loss of material due to environmental corrosion; loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI	Inservice Inspection—ASME Section XI, Subsection IWF Program (B.1.16)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Group B1.1—high-strength low-alloy bolts (Item Number 3.5.1-33)	Crack initiation and growth due to SCC	Bolting integrity	Inservice Inspection—ASME Section XI, Subsection IWF Program (B.1.16); Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)

The staff's review of the structures and component supports followed three separate approaches. One approach, documented in Section 3.5.2.1 of this SER, involves the staff's review of the AMR results for components in the structures and commodities that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.5.2.2 of this SER, involves the staff's review of the AMR results for components in the structures and commodities that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.5.2.3 of this SER, involves the staff's review of the AMR results for components in the structures and commodities that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. The staff documents its review of AMPs credited to manage or monitor aging effects of the structures and component supports in Section 3.0.3 of this SER.

3.5.2.1 Aging Management Evaluations That Are Consistent with the GALL Report, for Which No Further Evaluation Is Required

Summary of Technical Information in the Application

In Section 3.5.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the structures and component supports components:

- Boric Acid Corrosion Prevention Program
- Containment Leakage Rate Testing Program
- Inservice Inspection—ASME Section XI, Subsection IWE Program
- Inservice Inspection—ASME Section XI, Subsection IWF Program
- Inservice Inspection—ASME Section XI, Subsection IWL Program
- Structures Monitoring Program
- Structures Monitoring—Crane Inspection Program
- Structures Monitoring—Divider Barrier Seal Inspection Program
- Structures Monitoring—Ice Basket Inspection Program
- Structures Monitoring—Masonry Wall Program
- Water Chemistry Control Program
- System Testing Program
- Fire Protection Program

Staff Evaluation

In Tables 3.5.2-1 through 3.5.2-5 of the LRA, the applicant provided a summary of AMRs for the containment, containment internals, auxiliary building, turbine building, screenhouse, yard structures, and structural commodities, and identified which AMRs are considered consistent with the GALL Report.

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 does not recommend further evaluation, the staff performed an audit and review to determine whether the GALL Report evaluation bounded the plant-specific components contained in these GALL Report component groups.

The applicant provided a note for each AMR line item describing the alignment of the information in the tables with the information in the GALL Report. The staff audited those

AMRs with notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP identified by the applicant is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the applicant took some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that it had reviewed and accepted the applicant's exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report, and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant could not find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component applies to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different, but consistent with the GALL Report for material, environment, and aging effect. In addition, the applicant took some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component applies to the component under review. The staff verified whether it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff reviewed the information provided in the LRA and program bases documents, which are available at the applicant's engineering office. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs.

3.5.2.1.1 Loss of Material due to Corrosion in Accessible Areas Only

In LRA Table 3.5.1, Item 3.5.1-14, the applicant stated that a loss of material due to corrosion in accessible areas only does not require further evaluation. The applicant does not rely upon protective coatings to manage the effects of aging at CNP.

The staff noted that although the applicant did not credit protective coatings, damage to protective coatings may accelerate corrosion. Therefore, the protective coatings have the potential to exacerbate the aging effect. During the audit, the staff asked the applicant to address damage to protective coatings. The applicant discussed the use of external coatings and wrappings, the measures it takes during excavation of buried pipes, and inspections it performs when buried pipe is exposed. The staff finds these explanations acceptable.

On the basis of its audit and review, the staff determined that the applicant's references to the GALL Report are acceptable, that the line items are consistent with the GALL Report, and that no further staff review is required with respect to AMRs not requiring further evaluation, as identified in LRA Table 3.5.1.

In LRA Table 3.5.2-3, the applicant stated that the Structures Monitoring Program will be used for the aging management of water control structures. In Section B.1.32 of Appendix B to the LRA, the applicant stated that this program is consistent with the GALL Report. However, the staff's review found that the applicant did not compare the Structures Monitoring Program with GALL AMP XI.S7, "RG 1.127 Program," pursuant to the GALL Report. In order to ensure that the Structures Monitoring Program can be used to cover the water control structures, the staff requested the applicant to compare the Structures Monitoring Program with GALL AMP XI.S7 and demonstrate that the Structures Monitoring Program is suitable for managing the aging effects of water control structures. The staff identified this as RAI 3.5-7.

In the submittal dated June 8, 2004, the applicant responded to this RAI as follows:

> Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, is identified as an acceptable basis for developing an inservice inspection and surveillance program for water control structures in NUREG 1801, Section XI.S7. For plants not committed to RG 1.127, such as CNP, managing aging effects associated with structures and structural components may be included in the Structures Monitoring Program. The major water control structures at CNP are the screenhouse (intake structure) and the roadway west of the screenhouse. CNP uses the Structures Monitoring Program described in LRA Section B.1.32 to mange the effects of aging on water control structures. The Structures Monitoring Program, with enhancements, is consistent with NUREG-1801, Section XI.S6.
>
> The attributes that are in NUREG 1801, Section XI.S7, aging management program, but not in the CNP Structures Monitoring Program, are attributes dealing with earthen embankments water control structures. NUREG 1801, Section XI.S7, refers to RG 1.127 which proposes inspection parameters, including settlement, depressions, sink holes, slope stability (*e.g.*, irregularities in alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features,

and frequency (not to exceed five years) for earthen embankment water control structures. During the CNP aging management review, the aging effects requiring management for earthen structures (roadway) were determined to be loss of material, loss of form and change in material properties. As indicated in LRA Section B.1.32, the Structures Monitoring Program will be enhanced to include visual inspections to manage aging effects for the roadway west of the screenhouse. The visual inspections will detect degradation of the roadway due to the identified aging effects. The remaining water control structure (screenhouse) is similar to other CNP structures that are addressed by the Structures Monitoring Program. The Structures Monitoring Program will be effective in managing the effects of aging for water control structures.

In addition, the applicant provided the following comparison of the CNP Structures Monitoring Program with GALL AMP XI.S7 to demonstrate the applicability of the Structures Monitoring Program for the aging management of water control structures:

Aging Management Program Elements

1. Scope of Program

   a. NUREG 1801 Section XI.S7, Scope

      RG 1.127 applies to water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The water control structures included in the RG 1.127 program are concrete structures; embankment structures; spillway structures and outlet works; reservoirs; cooling water channels and canals, and intake and discharge structures; and safety and performance instrumentation.

   b. Comparison

      Water control structures are included in CNP Structures Monitoring Program. The Structures Monitoring Program scope includes the screenhouse and, as indicated in LRA Section B.1.32, the program will be enhanced to include the roadway west of the screenhouse.

2. Preventive Action

   a. NUREG-1801, Section XI.S7, Preventive Action

      No preventive actions are specified; RG 1.127 is a monitoring program.

   b. Comparison

      No preventive actions are included in the Structures Monitoring Program and none are required to address water control structures. The CNP preventive actions are consistent with NUREG 1801, Section XI.S7.

3. Parameters Monitored or Inspected

a. NUREG 1801 Section XI.S7, Parameters Monitored or Inspected

RG 1.127 identifies the parameters to be monitored and inspected for water control structures. The parameters vary depending on the particular structure. Parameters to be monitored and inspected for concrete structures include cracking, movements (*e.g.*, settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage. Parameters to be monitored and inspected for earthen embankment structures include settlement, depressions, sink holes, slope stability (*e.g.*, irregularities in alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features. Further details of parameters to be monitored and inspected for these and other water-control structures are specified in Section C.2 of RG 1.127.

b. Comparison

For concrete water control structures at CNP, the specific parameters monitored or inspected were selected to ensure that aging degradation leading to loss of intended functions is detected and the extent of degradation is determined. The parameters monitored or inspected (such as cracking, settlement, leakage, and water infiltration) were selected considering industry codes, standards and guidelines, and also consider industry and plant-specific operating experience. Settlement and erosion of porous concrete subfoundations are not problems at CNP, so a site de-watering system is not necessary. Consistent with NUREG-1801, Section XI.S6, the Structures Monitoring Program adequately addresses concrete and steel structure parameters to be monitored that are applicable to water control structures.

The Structures Monitoring Program will be enhanced to include parameters monitored for earthen structures (roadway west of the screenhouse). In accordance with NUREG 1801, Section XI.S6, parameters to be monitored and inspected for earthen embankment structures will consider industry codes, standards and guidelines, RG 1.127, and also consider industry and plant-specific operating experience.

4. Detection of Aging Effects

a. NUREG 1801, Section XI.S7, Detection of Aging Effects

Visual inspections are primarily used to detect degradation of water control structures. In some cases, instruments have been installed to measure the behavior of water-control structures. RG 1.127 indicates that the available records and readings of installed instruments are to be reviewed to detect any unusual performance or distress that may be indicative of degradation. RG 1.127 describes periodic inspections, to be performed at least once every five years. Similar intervals of five years are specified in ACI 349.3R for inspection of structures continually exposed to fluids or retaining fluids. Such intervals have been shown to be adequate to detect degradation of water control structures before they have a significant effect on plant safety. RG 1.127 also describes special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls.

b. Comparison

As indicated in LRA Section B.1.32, the Structures Monitoring Program will be enhanced to include detection of aging effects for the roadway west of the screenhouse. This enhancement will include inspecting the roadway for degradation or damage following a significant natural phenomenon, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. When enhanced, the examination criteria for the roadway will detect degradation of the roadway due to weather related damage.

The screenhouse is designed as a seismic Class I structure providing protection to safety related equipment from seismic events, tornado-velocity wind effects, tornado-borne missiles and flood conditions anticipated due to a seiche or surge phenomenon. Consistent with NUREG 1801, Section XI.S6, the detection of aging effects for water control structures concrete and steel elements is adequately addressed in the Structures Monitoring Program. Inspection methods, inspection schedule, and inspector qualifications are commensurate with industry codes, standards, guidelines, and also consider industry and plant specific operating experience. Special inspections are performed following the occurrence of significant natural phenomena, such as earthquakes, floods, seiche, severe weather, and fires.

5. Monitoring and Trending

a. NUREG 1801, Section XI.S7, Monitoring and Trending

Water control structures are monitored by periodic inspection as described in RG 1.127. In addition to monitoring the aging effects identified in Attribute (3) above, inspections also monitor the adequacy and quality of maintenance and operating procedures. RG 1.127 does not discuss trending.

b. Comparison

Consistent with NUREG-1801, Section XI.S6, CNP structures are monitored in accordance with 10 CFR 50.65. This approach is adequate for managing aging effects associated with water control structures included in the Structures Monitoring Program.

6. Acceptance Criteria

   a. NUREG 1801, Section XI.S7, RG 1.127, Acceptance Criteria

   Acceptance criteria to evaluate the need for corrective actions are not specified in RG 1.127. However, the 'Evaluation Criteria' provided in Chapter 5 of ACI 349.3R 96 provides acceptance criteria (including quantitative criteria) for determining the adequacy of observed aging effects and specifies criteria for further evaluation. Although not required, plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R 96 are acceptable. Acceptance criteria for earthen structures such as dams, canals, and embankments are to be consistent with programs falling within the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC) or the U.S. Army Corps of Engineers.

   b. Comparison

   The Structures Monitoring Program acceptance criteria are consistent with NUREG 1801, Section XI.S6, for concrete and steel components of water control structures. Including the roadway west of the screenhouse in the Structures Monitoring Program will result in developing acceptance criteria for visual inspections. When enhanced, acceptance criteria will be selected to ensure that the need for corrective actions will be identified before loss of intended functions. Acceptance criteria will be commensurate with industry codes, standards and guidelines, and will also consider industry and plant-specific operating experience.

7, 8, 9. Corrective Actions, Confirmation Process, and Administrative Controls

CNP applies the requirements of 10 CFR Part 50, Appendix B, to the Structures Monitoring Program through the use of the Corrective Action Program. The Structures Monitoring Program Corrective Actions, Confirmation Process, and Administrative Controls attributes are applicable to water control structures without enhancement.

10. Operating Experience

Operating experience discussed in LRA Section B.1.32 applies to water control structures with the exception of the roadway west of the screenhouse. Operating experience with the roadway was not discussed in LRA Section B.1.32 since the Structures Monitoring Program does not yet include the roadway; however, the operating experience review identified no significant degradation of the roadway.

> The Structures Monitoring Program will effectively manage the aging effects requiring management for water control structures at CNP with enhancements identified in LRA Section B.1.32.
>
> In summary, with enhancements, the Structures Monitoring Program will effectively manage the aging effects requiring management for water control structures at CNP.

The staff's review of this RAI response confirms that the applicant demonstrated that the Structures Monitoring Program is suitable for managing the aging effects of water control structures. On this basis, RAI 3.5-7 is resolved.

On the basis of its audit, the staff concludes that the applicant demonstrated that it will adequately manage the effects so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Conclusion</u>

The staff verified the applicant's claim of consistency with GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the applicant demonstrated that it will adequately manage the effects of aging for these components so that their intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 Aging Management Evaluations That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

In Section 3.5.2.2 of the LRA, the applicant provided further evaluation of aging management for structures and component supports as recommended by the GALL Report. The applicant provided information concerning how it will manage the following aging effects:

- aging of inaccessible concrete areas (PWR containments)
- cracking, distortion, and increases in component stress levels due to settlement, as well as reduction of foundation strength due to erosion of porous concrete subfoundations, if not covered by the Structures Monitoring Program (PWR containments)
- reduction of strength and modulus of concrete structures due to elevated temperature (PWR containments)
- loss of material due to corrosion in inaccessible areas of the steel containment shell or liner plate (PWR containments)
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature (PWR containments)
- cumulative fatigue damage (PWR containments)
- cracking due to cyclic loading and SCC (PWR containments)
- aging of structures not covered by the Structures Monitoring Program (Class I structures)
- aging management of inaccessible areas (Class I structures)

- aging of supports not covered by the Structures Monitoring Program (component supports)
- cumulative fatigue damage due to cyclic loading (component supports)

Staff Evaluation

For component groups evaluated in the GALL Report for which the applicant 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 it further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.5.2.2 of the SRP-LR. The staff documents its audit and review in the audit and review report.

The GALL Report indicates that the applicant should perform further evaluation for the aging effects described in the following sections of this SER.

3.5.2.2.1 PWR Containments

The staff reviewed Section 3.5.2.2.1 of the LRA against the criteria in Section 3.5.2.2.1 of the SRP-LR, which addresses several areas discussed below.

Aging of Inaccessible Concrete Areas. The staff reviewed LRA Section 3.5.2.2.1.1 against the criteria in SRP-LR Section 3.5.2.2.1.1. In LRA Section 3.5.2.2.1.1, the applicant addressed aging of inaccessible concrete areas for the containment. 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 GALL Report recommends GALL AMP XI.S2, "ASME Section XI, Subsection IWL," for managing the aging of the accessible portions of the containment structures. The applicant addressed this with the Inservice Inspection—ASME Section XI, Subsection IWL Program (CNP AMP B.1.17), which the staff evaluates in Section 3.0.3.2.8 of this SER. Subsection IWL exempts from examination those portions of the concrete containment that are inaccessible (*e.g.*, foundation, below grade exterior walls, or concrete covered by a liner).

In the LRA, the applicant stated that it also used the Structures Monitoring—Structures Monitoring Program (CNP AMP B.1.32) where accessible areas are monitored for evidence of aging effects that may be applicable to containment structures. The staff reviewed this program and concludes that it is consistent with GALL AMP XI.S6. Section 3.0.3.2.12 of this SER documents this program.

The GALL Report, Volume 2, Chapter II, Table A1 (as modified by ISG-3, "Concrete Aging Management Program"), recommends further evaluation to manage the aging effects for containment concrete components located in inaccessible areas if the aging mechanisms of (1) freeze-thaw, (2) leaching of calcium hydroxide, (3) aggressive chemical attack, (4) reaction with aggregates, or (5) corrosion of embedded steel are significant. Possible aging effects for containment concrete structural components caused by these five aging mechanisms are cracking, change in material properties, and loss of material.

(1) freeze-thaw

Section 3.5.2.2.1.1 of the SRP-LR does not address freeze-thaw as an aging mechanism for concrete containments because the GALL Report does not recommend further evaluation. However, ISG-3 clarified the staff position that further evaluation is appropriate if the applicant's facility is subject to moderate-to-severe weathering conditions, unless the concrete meets certain specifications and subsequent inspections have confirmed that the aging mechanism has not caused degradation of the concrete.

CNP is located in a region considered to be subject to moderate weathering conditions. In the LRA, the applicant stated that its concrete structures are designed in accordance with ACI 318-63, "Building Code Requirements for Reinforced Concrete," which results in low permeability and resistance to aggressive chemical solutions by requiring the following:

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

In the LRA, the applicant stated that CNP concrete also meets requirements of ACI 201.2R-77, "Guide to Durable Concrete." The specifications ACI 318-63 and ACI 201.2R-77 use the same ASTM standards for selection, application, and testing of concrete.

The staff interviewed members of the applicant's technical staff and reviewed relevant operating experience to confirm that the loss of material from freeze-thaw has not been observed, either through the Inservice Inspection—ASME Section XI, Subsection IWL Program or the Structures Monitoring Program.

On the basis that concrete satisfying the requirements of ACI 318-63 will meet the requirements of ISG-3, and on the basis of an audit of operating experience evaluated under the Inservice Inspection—ASME Section XI, Subsection IWL and Structures Monitoring Programs, the staff finds that the containment Inservice Inspection Program will adequately manage loss of material and cracking due to freeze-thaw.

(2) leaching of calcium hydroxide

Section 3.5.2.2.1.1 of the SRP-LR states that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-3, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria cannot be satisfied.

The GALL Report states that leaching of calcium hydroxide becomes significant only if the concrete is exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, is well cured, has low permeability, and that cracking is well controlled.

In the LRA, the applicant stated that CNP concrete structures are not exposed to flowing water and are designed in accordance with specification ACI 318-63 and meet the requirements of guideline ACI 201.2R-77.

The staff finds that because ACI 318-63 provides assurance that the criteria of the GALL Report and ISG-3 are met, leaching of calcium hydroxide is not significant at CNP, and therefore the Inservice Inspection—ASME Section XI, Subsection IWL Program will be sufficient to manage increases in porosity and permeability from this aging mechanism. A plant-specific AMP is not required to address this aging effect.

(3) aggressive chemical attack

Section 3.5.2.2.1.1 of the SRP-LR states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report and updated in ISG-3 cannot be satisfied.

The GALL Report, as updated by ISG-3, states that aggressive chemical attack is not significant unless pH is less than 5.5, chlorides are greater than 500 ppm, or sulfates are greater than 1500 ppm. The ISG-3 guidelines also state that a plant-specific program is required to examine representative samples of below grade concrete when excavated for any reason.

In the LRA, the applicant stated that the below grade environment is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1,500 ppm).

On the basis of the information provided in the LRA, and the guidelines provided in the SRP-LR, the GALL Report, and ISG-3, the staff finds that increases in porosity and permeability, loss of material (spalling and scaling), and cracking due to aggressive chemical attack are not significant for concrete in inaccessible areas. The staff finds that the applicant has identified an appropriate plant-specific program for examining below grade concrete.

(4) reaction with aggregates

Section 3.5.2.2.1.1 of the SRP-LR does not address reaction with aggregates as an aging mechanism for concrete containments because the GALL Report does not recommend further evaluation. However, ISG-3 updated the staff position that further evaluation is appropriate if investigations, tests, or examinations have demonstrated that the aggregates are reactive.

In the LRA, the applicant stated that CNP concrete structures are designed in accordance with ACI 318-63 and meet the requirements of ACI 201.2R-77. The ACI standards call for testing aggregates at the time of construction.

On the basis of interviews with the applicant's technical staff, the staff confirmed that the results of those tests show that the aggregates used for concrete containment at CNP are not reactive. The staff finds that this aging effect does not require management at CNP.

(5) corrosion of embedded steel

Section 3.5.2.2.1.1 of the SRP-LR states that a loss of material due to corrosion of embedded steel could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report (updated in ISG-3) recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

For cracking, loss of bond, or loss of material (spalling and scaling) due to corrosion of embedded steel, the GALL Report states that a plant-specific program is only required if the below grade environment is aggressive. The ISG-3 guidelines also state that a plant-specific program is required to examine representative samples of below grade concrete when excavated for any reason.

In the LRA, the applicant credited the Inservice Inspection – ASME Section XI, Subsection IWL and Structures Monitoring – Structures Monitoring Programs for corrosion of embedded steel in accessible areas. In LRA Section 3.5.2.2.1.1, the applicant stated that, with respect to the aging of inaccessible concrete areas, the below grade environment is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1500 ppm).

On the basis of interviews with the applicant's technical staff, the staff determined that the environment at the time of construction was not aggressive, and that on the basis of subsequent testing it has remained within the limits identified in the GALL Report. The staff finds that this aging effect is not significant and is adequately managed in accordance with the criteria of the GALL Report.

The staff reviewed the results of the applicant's AMR for inaccessible concrete areas. On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving the aging management of inaccessible concrete areas for the containment, as recommended in the GALL Report and ISG-3.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking, Distortion, and Increases in Component Stress Level due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. The staff reviewed LRA Section 3.5.2.2.1.2 against the criteria in SRP-LR Section 3.5.2.2.1.2. In LRA Section 3.5.2.2.1.2, the applicant addressed (1) cracking, distortion, and increases in component stress level caused by settlement and (2) reduction of foundation strength resulting from erosion of porous concrete subfoundations in the containment. The applicant used the Structures Monitoring—Structures Monitoring Program, where the applicant monitors accessible areas for evidence of aging effects that may be applicable to containment structures. Section 3.0.3.2.12 of this SER evaluates this program, which is consistent with GALL AMP XI.S6.

Section 3.5.2.2.1.2 of the SRP-LR states that cracking, distortion, and increases in component stress level resulting from settlement could occur in PWR concrete and steel containments. A recent staff survey found that 12 nuclear reactor structures have porous concrete foundations

with high alumina content, but CNP structures are not in this group. These foundations are susceptible to reduction in strength and settlement potential resulting from erosion of cement from porous concrete. Some plants may rely on a dewatering system to lower the site ground water level. If the plant's CLB credits a dewatering system, the GALL Report recommends that the applicant verify the continued functionality of the dewatering system during the period of extended operation. The GALL Report recommends no further evaluation if the scope of the applicant's Structures Monitoring Program includes this activity.

The applicant stated in the LRA that it does not credit a dewatering system for controlling settlement because the applicant monitored settlement at CNP and confirmed that significant settlement is not occurring. Membrane waterproofing protects concrete within 5 feet of the highest known ground water level and shields the containment building concrete against exposure to ground water. Consequently, NRC IN 97-11, "Cement Erosion From Containment Subfoundations at Nuclear Power Plants," dated March 21, 1997, does not identify CNP as a plant susceptible to erosion of porous concrete subfoundations. Ground water was not aggressive during plant construction, and no changes in ground water chemistry conditions have been observed. The applicant included these components within its plant-specific Structures Monitoring Program, which will confirm adequate management of these aging effects.

The staff reviewed the AMR results involving management of aging effects resulting from settling and erosion of porous concrete subfoundations and confirmed that the Structures Monitoring Program addresses each of the affected SCs. On the basis of this review, the staff finds that the applicant has appropriately evaluated AMR results involving cracking, distortion, increases in component stress level from settlement, and reduction of foundation strength from erosion, as recommended in the GALL Report.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature</u>. The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3. In LRA Section 3.5.2.2.1.3, the applicant addressed the reduction of strength and modulus of concrete structures caused by elevated temperature in containments.

Section 3.5.2.2.1.3 of the SRP-LR states that reduction of strength and modulus of elasticity resulting from elevated temperatures could occur in PWR concrete and steel containments. The GALL Report calls for a plant-specific AMP and recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits (*i.e.*, general area temperature of 66 °C (150 °F) and local area temperature of 93 °C (200 °F)).

In LRA Section 3.5.2.2.1.3, the applicant stated that during normal operation, all areas within the containment building are below 66 °C (150 °F) ambient temperature except for the Unit 1 pressurizer enclosure, which is at 79 °C (160 °F). Several penetrations have been exposed to temperatures greater than 93 °C (200 °F). However, these were temporary, and the effects were negligible. Therefore, the applicant concluded that change in material properties from elevated temperature is an AERM for the containment concrete only for the pressurizer enclosure area for Unit 1, where ambient temperature exceeds 66 °C (150 °F).

The applicant concluded that its containment concrete structures are not subject to change in material properties resulting from elevated temperature. The applicant included these components within the scope of the Structures Monitoring—Structures Monitoring Program, evaluated in Section 3.0.3.2.12 of this SER, and the Inservice Inspection—ASME Section XI, Subsection IWL Program, evaluated in Section 3.0.3.2.8 of this SER, to monitor containment concrete for indications of the change in material properties aging effects.

The staff reviewed the AMR results involving management of aging effects resulting from elevated temperature and confirmed that the Inservice Inspection—ASME Section XI, Subsection IWL and Structures Monitoring Programs address each of the affected SCs within the pressurizer enclosure area. On the basis of this audit and review, the staff finds that the applicant appropriately evaluated AMR results involving reduction of strength and modulus resulting from elevated temperature, as recommended in the GALL Report.

On the basis that the concrete is only exposed to elevated temperatures within the pressurizer enclosure area, the staff finds that for all other locations the Structures Monitoring and Inservice Inspection—ASME Section XI, Subsection IWL Programs will appropriately manage the aging effect during the period of extended operation. The staff finds that no further evaluation is required.

The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging of the concrete resulting from elevated temperature 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).

<u>Loss of Material due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate</u>. The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4. In LRA Section 3.5.2.2.1.4, the applicant addressed the loss of material due to corrosion in inaccessible areas of the steel containment shell or the steel liner plate for the containment.

Section 3.5.2.2.1.4 of the SRP-LR states that the loss of material due to corrosion could occur in inaccessible areas of the steel containment shell or the steel liner plate for all types of PWR containments. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if the following specific criteria defined in the GALL Report cannot be satisfied:

- Concrete meeting the requirements of ACI 318 and the guidance of ACI 201.2R was used for the containment concrete in contact with the embedded containment shell or liner.

- The accessible concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner.

- The accessible portion of the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Code, Section XI, Subsection IWE requirements.

- Borated water spills and water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

In the LRA, the applicant stated that the containment concrete in contact with the steel liner plate is designed in accordance with ACI 318-63 and meets the requirements of ACI 201.2R-77. Accessible concrete is monitored for cracks under the Structures Monitoring Program. The accessible portions of the steel liner plate and moisture barrier where the liner becomes embedded are inspected in accordance with the Inservice Inspection—ASME Section XI, Subsection IWE Program. Spills (*e.g.*, borated water) are cleaned up in a timely manner. The applicant also stated that the aging effect of loss of material due to corrosion has not been significant for this liner plate.

The staff reviewed the Structures Monitoring Program and the Inservice Inspection—ASME Section XI, Subsection IWE Program and documents its evaluation in Sections 3.0.3.2.12 and Section 3.0.3.2.7 of this SER, respectively. Based on its review and on the basis that all of the criteria identified in the GALL Report are satisfied, the staff finds that an additional, plant-specific AMP is not required to manage inaccessible areas of the steel containment liner plate.

On the basis of its audit and review, the staff finds that the applicant has appropriately evaluated AMR results involving loss of material due to corrosion that could affect inaccessible areas of the steel liner plate and the containment liner plate. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. Section 4.5 of this SER addresses Section 3.5.2.2.1.5 of the LRA.

<u>Cumulative Fatigue Damage</u>. Section 4.6 of this SER addresses LRA Section 3.5.2.2.1.6.

<u>Cracking ue to Cyclic Loading and Stress Corrosion Cracking</u>. The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7. In LRA Section 3.5.2.2.1.7, the applicant addressed aging mechanisms that can lead to cracking of penetration sleeves and penetration bellows, such as cyclic loads and SCC. Section 4.6 of this SER evaluates cracking due to cyclic loading of the liner plate and penetrations, which is a TLAA.

Section 3.5.2.2.1.7 of the SRP-LR states that cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in containments. Further evaluation of inspection methods is recommended to detect cracking due to cyclic loading and SCC because visual examinations (VT-3) may be unable to detect this aging effect.

GALL AMP XI.S1 covers inspection of these items under examination categories E-B, E-F, and E-P (10 CFR Part 50, Appendix J pressure tests). Title 10, Section 50.55a, of the *Code of Federal Regulations* (10 CFR 50.55a) identifies examination categories E-B and E-F as optional during the current term of operation. For the period of extended operation, examination categories E-B and E-F and additional appropriate examinations to detect SCC in bellows assemblies and dissimilar metal welds are warranted to address this issue.

In order to manage this aging effect, the applicant used the Inservice Inspection—ASME Section XI, Subsection IWE Program, evaluated in Section 3.0.3.1 of this SER, and the Containment Leakage Rate Testing Program, evaluated in Section 3.0.3.1 of this SER. Section 3.5.2.2.1.7 of the SRP-LR recommends further evaluation of this aging effect for stainless steel penetration bellows and dissimilar metal welds. However, in LRA Tables 3.5.2-1 through 3.5.2-5, the applicant did not identify penetration bellows and dissimilar metal welds as subject to an AMR.

On the basis that penetration bellows and dissimilar metal welds at CNP are not subject to an AMR, the staff finds that cracking due to SCC is not an applicable aging effect for CNP. Therefore, an augmented inspection to detect cracking is not necessary.

On the basis of its review, the staff finds that the applicant has appropriately evaluated AMR results involving management of cracking due to SCC for containment components, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Class 1 Structures

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which addresses several areas discussed below.

Aging of Structures Not Covered by the Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.1. In LRA Section 3.5.2.2.2.1, the applicant addressed aging of Class 1 structures not covered by the Structures Monitoring Program.

Section 3.5.2.2.2.1 of the SRP-LR states that the GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the Structures Monitoring Program. Chapter III of the GALL Report describes this and includes (1) scaling, cracking, and spalling due to repeated freeze-thaw for Group 1–3, 5, and 7–9 structures, (2) scaling, cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Group 1–5 and 7–9 structures, (3) expansion and cracking due to reaction with aggregates for Group 1–5 and 7–9 structures, (4) cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for Group 1–5 and 7–9 structures, (5) cracks, distortion, and increases in component stress level due to settlement for Group 1–3, 5, and 7–9 structures, (6) reduction of foundation strength due to erosion of porous concrete subfoundations for Group 1–3 and 5–9 structures, (7) loss of material due to corrosion of structural steel components for Group 1–5 and 7–8 structures, (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1–5; and (9) crack initiation and growth due to SCC, as well as loss of material due to crevice corrosion of the stainless steel liner for Group 7–8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

Section 3.5.2.2.1.2 of the SRP-LR presents technical details of the aging management issue for structure/aging effect combination Items (5) and (6). Section 3.5.2.2.1.3 of the SRP-LR presents technical details of the aging management issue for Item (8).

In LRA Table 3.5.1, Item 20, the applicant credited its Structures Monitoring Program to manage all types of aging effects and all component groups except Group 6 of accessible interior and exterior concrete, and steel components of Class 1 structures. The staff reviewed this program and documents its evaluation in Section 3.0.3.2.12 of this SER. This section provides additional discussion of specific structure/aging effect combinations.

(1) freeze-thaw

Section 3.5.2.2.1.2 of the SRP-LR does not address freeze-thaw as an aging mechanism for concrete containments because the GALL Report does not recommend further evaluation. However, ISG-3 clarifies the staff position that further evaluation is appropriate if the applicant's facility is subject to moderate-to-severe weathering conditions, unless the concrete meets certain specifications and subsequent inspections have confirmed that the aging mechanism has not caused degradation of the concrete.

CNP is located in a region considered to be subject to moderate weathering conditions. In the LRA, the applicant stated that CNP structures are designed in accordance with ACI 318-63, which results in low permeability and resistance to aggressive chemical solutions by requiring the following:

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

In addition to ACI 318-63, the applicant stated in the LRA that its concrete also meets the requirements of ACI 201.2R-77. The specifications ACI 318-63 and ACI 201.2R-77 use the same ASTM standards for selection, application and testing of concrete.

The staff interviewed members of the applicant's technical staff and reviewed relevant operating experience to confirm that loss of material from freeze-thaw has not been observed, either through the Inservice Inspection—ASME Section XI, Subsection IWL Program or the Structures Monitoring Program.

On the basis that concrete satisfying the requirements of ACI 318-63 will meet the requirements of ISG-3, and on the basis of an audit of operating experience evaluated under the Structures Monitoring Program, the staff finds that the Structures Monitoring Program will adequately manage the loss of material and cracking due to freeze-thaw.

(2)(a) leaching of calcium hydroxide

Section 3.5.2.2.2.1 of the SRP-LR states that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-3, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas exposed to flowing water, unless the requirements of ACI 201.2R are met.

The GALL Report states that leaching of calcium hydroxide becomes significant only if the concrete is exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, well cured, has low permeability, and that cracking is well controlled.

In the LRA, the applicant stated that its concrete structures are designed in accordance with ACI 318-63 and meet the requirements of ACI 201.2R-77. The applicant also stated that its concrete is not exposed to flowing water.

The staff reviewed relevant operating experience, interviewed members of the applicant's technical staff, and reviewed ISG-3. The staff finds that, because ACI 318-63 provides assurance that the criteria of the GALL Report and ISG-3 are met, and because the applicant's concrete is not exposed to flowing water, leaching of calcium hydroxide is not significant at CNP. Therefore, the staff concludes that the Structures Monitoring Program will be sufficient for managing increases in porosity and permeability from this aging mechanism. A plant-specific AMP is not required to address this aging effect.

(2)(b) aggressive chemical attack

Section 3.5.2.2.2.1 of the SRP-LR states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack could occur in inaccessible areas of Class 1 structures. The GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report and updated in ISG-3 cannot be satisfied.

The GALL Report, as updated by ISG-3, states that aggressive chemical attack is not significant unless pH is less than 5.5, chlorides are greater than 500 ppm, or sulfates are greater than 1500 ppm. The ISG-3 guidelines also state that a plant-specific program is required to examine representative samples of below grade concrete when excavated for any reason. In the LRA, the applicant stated that the below grade environment is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1500 ppm).

The staff reviewed the information provided in the LRA, the basis documents, and the guidelines provided in the SRP-LR, the GALL Report, and ISG-3. On the basis of its review, the staff finds that increases in porosity and permeability, loss of material (spalling and scaling), and cracking due to aggressive chemical attack are not significant for concrete in inaccessible areas. The staff finds that the applicant has identified an appropriate plant-specific program for examining below grade concrete (specifically, an enhancement to the Structures Monitoring Program).

(3) reaction with aggregates

Section 3.5.2.2.1.1 of the SRP-LR does not address reaction with aggregates as an aging mechanism for concrete containments because the GALL Report does not recommend further evaluation. However, ISG-3 clarifies the staff's position that further evaluation is appropriate if investigations, tests, or examinations have demonstrated that the aggregates are reactive.

In the LRA, the applicant stated that its concrete structures are designed in accordance with ACI 318-63 and meet the requirements of ACI 201.2R-77. The ACI standards call for testing aggregates at the time of construction. On the basis of interviews with the applicant's technical staff, the staff confirmed that the results of those tests show that the aggregates used for concrete Class 1 structures at CNP are not reactive. The staff finds that no further evaluation is required.

(4) corrosion of embedded steel

Section 3.5.2.2.2.1 of the SRP-LR states that the loss of material due to corrosion of embedded steel could occur in inaccessible areas of Class 1 structures. The GALL Report (updated in ISG-3) recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

For cracking, loss of bond, and loss of material (spalling and scaling) due to corrosion of embedded steel, the GALL Report states that a plant-specific program is only required if the below grade environment is aggressive. The ISG-3 guidelines also state that a plant-specific program is required to examine representative samples of below grade concrete when excavated for any reason.

In the LRA, the applicant stated that the below grade environment is not aggressive because the environment at the time of construction had a measured pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1500 ppm, and subsequent testing has shown the environment has remained within these limits.

The staff finds that the applicant adequately manages this aging effect by the enhanced Structures Monitoring Program, in accordance with the criteria of the GALL Report, which Section 3.0.3.2.11 of this SER evaluates.

(5) settlement

Section 3.5.2.2.2.1 of the SRP-LR refers to Section 3.5.2.2.1.2 for discussion of settlement. Section 3.5.2.2.1.2 of the SRP-LR states that cracking, distortion, and increases in component stress level due to settlement could occur in Class 1 structures. Some plants may rely on a dewatering system to lower the site ground water level. If the plant's CLB credits a dewatering system, the GALL Report recommends verifying the continued functionality of the dewatering system during the period of extended operation. The GALL Report recommends no further evaluation if the scope of the applicant's Structures Monitoring Program includes this activity.

In the LRA, the applicant stated that it did not credit a dewatering system for control of settlement because it monitored settlement and confirmed that significant settlement was not occurring. Membrane waterproofing protects concrete within 5 feet of the highest known ground water level and shields the Class 1 concrete structures against exposure to ground water. Consequently, IN 97-11 does not identify CNP as a plant susceptible to erosion of porous concrete subfoundations. Ground water was not aggressive during plant construction, and no changes in ground water chemistry conditions have been observed. The applicant included these components within its plant-specific Structures Monitoring Program, which will confirm adequate management of these aging effects.

The staff reviewed the AMR results involving management of aging effects resulting from settling and erosion of porous concrete subfoundations and confirmed that the Structures Monitoring Program addresses each of the affected SCs. On the basis of this review, the staff finds that the applicant appropriately evaluated AMR results involving cracking, distortion, and increases in component stress level from settlement and reduction of foundation strength from erosion, as recommended in the GALL Report.

(6) erosion of porous concrete subfoundation

Section 3.5.2.2.2.1 of the SRP-LR refers to Section 3.5.2.2.1.2 for discussion of erosion of porous concrete subfoundation. Section 3.5.2.2.1.2 of the SRP-LR states that reduction of foundation strength resulting from erosion of porous concrete subfoundations could occur in all types of Class 1 structures. Some plants may rely on a dewatering system to lower the site ground water level. If the plant's CLB credits a dewatering system, the GALL Report recommends verifying the continued functionality of the dewatering system during the period of extended operation. The GALL Report recommends no further evaluation if the scope of the applicant's Structures Monitoring Program includes this activity.

The applicant stated that IN 97-11 does not identify CNP as a plant susceptible to erosion of porous concrete subfoundations. Therefore, this issue is not applicable to CNP.

(7) corrosion of structural steel components

Section 3.5.2.2.2.1 of the SRP-LR states that corrosion of structural steel components could occur, and that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

In LRA Section 3.5.2.2.1, the applicant stated that corrosion of structural steel components is an aging effect managed by the Structures Monitoring Program.

The staff reviewed the AMR results involving management of aging effects resulting from the corrosion of structural steel components and confirmed that the Structures Monitoring Program, evaluated in Section 3.0.3.2.12 of this SER, addresses each of the affected SCs. On the basis of this audit and review, the staff finds that the applicant has appropriately evaluated AMR results involving this aging effect and that the Structures Monitoring Program adequately manages corrosion of structural steel components.

(8) elevated temperatures

Section 3.5.2.2.2.1 of the SRP-LR refers to Section 3.5.2.2.1.3 for a discussion of elevated temperatures. Section 3.5.2.2.1.3 of the SRP-LR states that a reduction of strength and modulus of elasticity resulting from elevated temperatures could occur in Class 1 structures in Groups 1–5. The GALL Report calls for a plant-specific AMP and recommends further evaluation if any portion of the concrete components exceeds specified temperature limits (*i.e.*, general area temperature 66 °C (150 °F) and local area temperature 93 °C (200 °F)).

In LRA Section 3.5.2.2.2.1, the applicant stated that during normal operation, all concrete areas in Class 1 structures are below 66 °C (150 °F) ambient temperature except for the Unit 1 pressurizer enclosure, discussed in LRA Section 3.5.2.2.1.3. The staff's evaluation of the Unit 1 pressurizer enclosure elevated temperature appears in Section 3.5.2.2.1.3 of this SER.

The staff reviewed the AMR results involving management of aging effects resulting from elevated temperature and confirmed that the Structures Monitoring Program, evaluated in

Section 3.0.3.2.12 of this SER, addresses each of the affected SCs. On the basis of this review, the staff finds that the applicant appropriately evaluated AMR results involving the reduction of strength and modulus resulting from elevated temperature, as recommended in the GALL Report, and that the Structures Monitoring Program adequately manages this effect.

(9) *aging effects for stainless steel liners for tanks*

In LRA Section 3.5.2.2.2.1, the applicant stated that the structural AMRs do not include any tanks with stainless steel liners. The applicant evaluated tanks that are subject to an AMR with the respective mechanical system's AMR.

In LRA Section 3.5.2.2.2.1 and Tables 3.5.2-1 through 3.5.2-5, the applicant indicated that it will not use the Structures Monitoring—Structures Monitoring Program (CNP AMP B.1.32) to manage the aging effects resulting from the loss of material for those structural elements potentially exposed to borated water leakage. These structural elements include block wall grating and framing (carbon steel), missile shield (carbon steel), superstructure framing (carbon steel), baseplates (carbon steel), baseplate of embedded unistrut (galvanized steel), blowout panels (carbon steel), cable tray and conduit supports (carbon steel), cable trays and conduits (galvanized steel and aluminum), component supports (carbon steel), electrical instrument panels and enclosures (carbon steel), HVAC duct supports (carbon steel and galvanized steel), instrument line supports (carbon steel and galvanized steel), instrument racks and frames (carbon steel and galvanized steel), miscellaneous embedments (carbon steel), carbon steel pipe sleeves (mechanical/electrical, not penetrating the containment liner plate), piping supports (carbon steel), carbon steel stair systems (stairs, ladders, and grating including supports), tube tracks (carbon steel), carbon steel anchor bolts (includes switchyard structures and tank anchors), Class 1 anchor bolts (carbon steel), certain threaded fasteners (carbon steel), and reactor cavity missile block tiedowns (carbon steel).

For the aging effects caused by boric acid corrosion, the applicant proposed to use the Boric Acid Corrosion Prevention Program (CNP AMP B.1.4). As stated in the LRA, this program is comparable with GALL AMP XI.M10. The LRA also states that, with program enhancement to include electrical components in addition to ferritic steel, this AMP will be consistent with the program described in GALL AMP XI.M10, and will be used to cover steel structural elements related to or adjacent to the boronic injection system, including those located inside the auxiliary building.

The staff's review of LRA Table 3.5.2-5 found that this AMP will be used to manage aging effects related to the loss of materials in some structural elements, such as anchor bolts of switchyard structures and tank anchors. Therefore, in RAI 3.5-6, the staff requested that the applicant (a) clearly state that the scope of this AMP will cover these structural elements and (b) clarify whether this AMP will cover any other structures and structural components not located in the containment or the auxiliary building.

In the submittal dated June 8, 2004, the applicant provided its response to these two questions as follows:

> (a) The Boric Acid Corrosion Prevention Program is implemented by a plant procedure. The procedure is applicable where the potential exists to degrade ferritic steel components within the reactor coolant pressure boundary and

other plant systems due to contact with borated water. The scope of the Boric Acid Corrosion Prevention Program includes structures and structural components potentially exposed to borated water leakage, whether they are included in the containment, auxiliary building, or other locations on the plant site (including yard structures). Switchyard structures are not exposed to borated water leakage, but some tank anchors are, as discussed in response to sub-part (b), below.

(b) The Boric Acid Corrosion Prevention Program listed for anchor bolts in LRA Table 3.5.2 5 applies only to anchor bolts with the potential for exposure to borated water leakage. Structural components located outside the containment and auxiliary buildings that are covered by the Boric Acid Prevention Corrosion Program are the refueling water storage tank anchorage in the yard.

In its response, the applicant clarified that the Boric Acid Corrosion Prevention Program will cover structures and structural components potentially exposed to borated water leakage, whether they are included in the containment, the auxiliary building, or other locations on the plant site (such as yard structures), including the anchors of switchyard structures and tanks. On this basis, RAI 3.5-6 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated AMR results involving aging management of accessible interior and exterior concrete and steel components of Class 1 structures (except Group 6, water-control structures, discussed in Section 3.0.3.2.11 of this SER), and the Structures Monitoring Program covers them all. This is consistent with the recommendations of the GALL Report. The staff finds that the applicant has demonstrated that it will adequately manage the effects of aging 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).

Aging Management of Inaccessible Areas. The staff reviewed LRA Section 3.5.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2. In LRA Section 3.5.2.2.2.2, the applicant addressed aging of inaccessible areas of Class 1 structures.

Section 3.5.2.2.2.2 of the SRP-LR states that cracking, spalling, and increases in porosity and permeability resulting from aggressive chemical attack, as well as cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in below grade inaccessible concrete areas. The GALL Report recommends further evaluation to manage these aging effects in inaccessible areas of Group 1–3, 5, and 7–9 structures, if an aggressive below grade environment exists. The ISG-3 guidelines identify additional requirements.

The GALL Report, as updated by ISG-3, states that aggressive chemical attack and corrosion of embedded steel are not significant unless pH is less than 5.5, chlorides are greater than 500 ppm, or sulfates are greater than 1500 ppm. The ISG-3 guidelines also state that a plant-specific program is required to examine representative samples of below grade concrete when excavated for any reason.

In the LRA Section 3.5.2.2.2.2, the applicant stated that the below grade environment is not aggressive (pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than

1500 ppm). Inspections of accessible concrete have not revealed degradation from aggressive chemical attack or corrosion of embedded steel.

On the basis that the below grade environment is not aggressive, and that excavated concrete has been and will continue to be monitored, the staff finds that the applicant adequately manages increases in porosity and permeability, loss of material (spalling and scaling), and cracking due to aggressive chemical attack, as well as cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for concrete in inaccessible areas.

In LRA Section 3.5.2.2.2.2, the applicant stated that inspection of accessible concrete has not revealed degradation related to corrosion the of embedded steel. The applicant also stated that as the CNP below grade environment is not aggressive, corrosion of embedded steel is not an applicable aging mechanism for CNP concrete. The staff agrees with this statement only for the case of uncracked reinforced concrete elements. However, the staff is concerned that the embedded structural foundations may crack from settlement, and corrosion of reinforcing steel may occur, even if the below grade environment is not aggressive. The staff requested the applicant to provide additional information to justify the validity of the LRA statement. The staff identified this as RAI 3.5-5.

In the response dated June 8, 2004, the applicant stated the following:

> As discussed in LRA Section 3.5.2.2.1.2, cracking due to settlement is not applicable to CNP concrete structures. Settlement was monitored at CNP until discontinued after confirmation that significant settlement was not occurring. In addition, NUREG 1800, Section 3.5.2.2.2.2, recommends further evaluation to manage aging effects only if specific criteria defined in NUREG 1801 cannot be met. Those criteria are the criteria for an aggressive environment as stated in NUREG 1801, Volume 2, Item III.A1.1 e. Since the CNP below-grade environment is not aggressive, corrosion of embedded steel is not an applicable aging effect/mechanism.

In addition to the response above, the applicant provided its monitoring results of ground water chemistry in its response to RAI 3.5-8, and indicated that the pH is higher than 5.5, the chloride contents are much lower than 500 ppm, and sulfate contents are much lower than 1500 ppm. According to GALL Report, Volume 2, Item III.A3.1-e, the below grade environment is not aggressive, and the aging effect resulting from rebar corrosion will be insignificant, so no further evaluation is necessary. On this basis, RAI 3.5-5 is resolved.

Section 3.5.2.2.2.1.(2), "Leaching of Calcium Hydroxide and Aggressive Chemical Attack," of the LRA states that the CNP concrete is not exposed to flowing water, and the below grade environment is not aggressive (pH is greater than 5.5, chlorides are less than 500 ppm, and sulfates are less than 1500 ppm). Therefore, the LRA concludes that increases in porosity and permeability and loss of strength of due to leaching of calcium hydroxide are not applicable aging effects for CNP concrete structures. However, in the Structures Monitoring Program, the applicant did not commit to periodically monitor the ground water chemistry as specified in the GALL Report. Therefore, the staff requested the applicant to (1) either augment its Structures Monitoring Program to include the monitoring of ground water chemistry in order to ensure that the ground water will be continuously nonaggressive or (2) provide a technical basis to justify that there is no need to continuously monitor the ground water chemistry. The staff identified this as RAI 3.5-8.

In its response, the applicant stated the following:

> Sample data tabulated below indicates the limiting chemistry parameters have shown no significant increase and are still far below established limits. Because existing data show no significant change over a period of approximately 25 years, ground water chemistry is not anticipated to significantly change in the future. Therefore, periodic monitoring of ground water chemistry is not required to assure the non aggressiveness of the below grade environment.

Sample	Sample date	Sample Well 1A	Sample Well 12
pH	03/04/1976	6.4	7.8
	01/15/2002	7.1	7.4
Chloride (ppm)	03/04/1976	20.3	9.7
	01/15/2002	10	12
Sulfate (ppm)	03/04/1976	18.1	310.3
	01/15/2002	134	67

On the basis of the information provided above, the staff concurs with the applicant's conclusion that the changes in water chemistry for the past 25 years are insignificant and the total water contents are much lower than the GALL Report criteria. In addition, Appendix B to the applicant's environmental report for the operating license renewal stage (*i.e.*, the license renewal environmental report) excerpts the discharge permit (MDEQ permit No. M00988) and states that the discharge permit requires groundwater sampling from four onsite wells (plus a background monitoring well). The quarterly monitoring includes sampling and analyzing the ground water for pH, chloride, sulfates, and a number of other parameters. According to the applicant, this requirement has been implemented since 1984. The results of this sampling, including compliance with specified limitations, are reported to the Department of Environmental Quality (DEQ) on a quarterly basis, and can be used to justify the quality of groundwater. On the basis discussed above, the staff considers RAI 3.5-8 resolved.

3.5.2.2.3 Component Supports

The staff reviewed LRA Section 3.5.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.3, which addresses several areas discussed below.

<u>Aging of Supports Not Covered by the Structures Monitoring Program</u>. The staff reviewed LRA Section 3.5.2.2.3.1 against the criteria in SRP-LR Section 3.5.2.2.3.1. In LRA Section 3.5.2.2.3.1, the applicant addressed aging of component supports that are not managed by the Structures Monitoring Program.

Section 3.5.2.2.3.1 of the SRP-LR states that 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 resulting from the degradation of the surrounding concrete for Group B1–B5 supports, (2) loss of material due to environmental corrosion for Group B2–B5 supports, and (3) reduction/loss of isolation function resulting from the degradation of vibration isolation elements for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

(1) reduction in concrete anchor capacity resulting from surrounding concrete for Group B1–B5 supports

In LRA Section 3.5.2.2.3.1, the applicant stated that the Structures Monitoring Program includes its component supports for Groups B2–B5, and the Inservice Inspection—ASME Section XI, Subsection IWF Program manages component supports for Group B1. The staff reviewed these programs and documents its evaluation in Sections 3.0.3.2.12 and 3.0.3.1 of this SER, respectively.

On the basis of its review of the AMR results involving the aging effects of reduction in concrete anchor capacity from surrounding concrete, as well as its review of the AMPs that manage the aging effects, the staff finds that the applicant adequately manages these aging effects for component supports.

(2) loss of material due to environmental corrosion for Group B2–B5 supports

In LRA Section 3.5.2.2.3.1, the applicant stated that the loss of material due to corrosion of steel support components is an AERM at CNP. The applicant manages this aging effect with the Structures Monitoring Program. The staff finds that the applicant adequately manages this aging effect for component supports.

(3) reduction/loss of isolation function resulting from degradation of vibration isolation elements for Group B4 supports

In LRA Section 3.5.2.2.3.1, the applicant stated that no vibration isolation elements for Group B4 supports are subject to an AMR. The staff finds that the applicant has appropriately evaluated AMR results involving the aging management of component supports, as recommended in the GALL Report. The staff finds that the applicant demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cumulative Fatigue Damage due to Cyclic Loading. Section 4.6 of this SER evaluates cumulative fatigue damage as a TLAA.

3.5.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

The NRC Office of Nuclear Reactor Regulation, Division of Inspection Program Management staff reviewed LRA Section 3.5.2.2.4. Section 3.0.4 of this SER addresses this issue.

Conclusion

On the basis of its review 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 determined that the applicant adequately addressed the issues it further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in the SRP-LR. Because the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3 AMR Results That Are Not Consistent with the GALL Report or Are Not Addressed in the GALL Report

Summary of Technical Information in the Application

In Tables 3.5.2-1 through 3.5.2-5 of the LRA, the staff reviewed additional details of the results of the AMRs for materials, environments, AERMs, and AMP combinations that are not consistent with the GALL Report.

In Tables 3.5.2-1 through 3.5.2-5, the applicant indicated with notes F through J, where applicable, that the GALL Report does not evaluate either the identified components or the material and environment combinations. The applicant provided information concerning how it will manage the AERMs.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for the identified component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that neither the identified component nor the material and environment combination is evaluated in the GALL Report.

Staff Evaluation

For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB during the period of extended operation. The following sections discuss the staff evaluation.

3.5.2.3.1 Containment

Summary of Technical Information in the Application

In Section 3.5.2.1.1 of the LRA, the applicant identified the materials, environments, and AERMs for containment components. The applicant identified the following AMPs that will manage the aging effects for the containment components:

- Boric Acid Corrosion Prevention Program
- Containment Leakage Rate Testing Program
- Inservice Inspection—ASME Section XI, Subsection IWE Program
- Inservice Inspection—ASME Section XI, Subsection IWF Program
- Inservice Inspection—ASME Section XI, Subsection IWL Program
- Structures Monitoring Program
- Structures Monitoring—Crane Inspection Program
- Structures Monitoring—Divider Barrier Seal Inspection Program
- Structures Monitoring—Ice Basket Inspection Program
- Water Chemistry Control Program

In Table 3.5.2-1 of the LRA, the applicant summarized the AMRs for the containment components and identified AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

The following paragraphs discuss RAIs related to the containment pressure boundary components as summarized in Tables 3.5.1 and 3.5.2-1, the applicant's responses, and the staff's positions.

Aging Effects

RAI 3.5-1

In discussing Item 3.5.1-3 of Table 3.5.1 of the LRA, the applicant indicated that the aging effects related to the loss of material due to corrosion of bellows and dissimilar metal welds are managed consistent with the GALL Report. The GALL Report recommends examining penetration bellows and the associated dissimilar welds based on operating experience with the SCC of bellows as documented in NRC IN 92-20, "Inadequate Local Leak Rate Testing," dated March 3, 1992. In RAI 3.5-1, the staff requested the following in relation to the examination and/or testing of containment penetration bellows:

> How many penetration bellows are in the Cook containments? Please summarize the operating experience related to the examination of these bellows. If provisions are made to assess their leaktightness (as they are not accessible for visual examination), please provide a summary of these provisions (including frequency of tests), and indicate if such leaktightness assessment of the bellows is part of the LRA AMP [aging management program] B.1.15 or B.1.8.

In its response, the applicant stated the following:

> As stated in Updated Final Safety Analysis Report (UFSAR) Section 1.4.7, Criterion 56, and Section 5.2.4.2, Fuel Transfer Penetration, penetration expansion bellows are not used to maintain containment integrity and do not serve as part of the containment pressure boundary. Therefore, CNP expansion bellows do not serve an intended function, and are not subject to aging management review. No provisions are made to assess their leaktightness.

For the purpose of clarification, the staff requested the applicant to confirm that the CNP containments do not have any containment pressure boundary bellows.

In response, the applicant stated the following:

> Containment penetration bellows do not provide a pressure-boundary function and are not part of the CNP containment isolation barrier. The Updated Final Safety Analysis Report excerpts provided in I&M's original response to RAI 3.5-1 in the I&M letter dated June 8, 2004, (Reference 1) provide the current licensing basis that reflects this. This basis has also been previously been reported to, and reviewed by, the NRC Staff in the I&M license amendment request dated April 11, 2002 (Reference 2) and the NRC safety evaluation that approved the license amendment, dated February 25, 2003 (Reference 3).
>
> For clarification, the component type "Fuel transfer tube penetration" listed in LRA Table 3.5.2-1 includes only the mechanical components (tube and closure flange) that are depicted on license renewal drawings LRA-1-5140 and LRA-2-5140 at locations L8 and L4, respectively. The bellows expansion joints that were provided on the outer pipe to compensate for any differential movement between the inner and outer pipes and also between the containment and auxiliary building structures do not serve as part of the containment pressure boundary. Because penetration bellows do not provide a containment pressure-boundary function, they are not included in the scope of license renewal and are not subject to aging management.

During a telephone conference call dated September 16, 2004, the applicant explained the purpose of bellows associated with the fuel transfer tube penetration as providing flexibility of movement between the fuel transfer tube and its penetration sleeves. As indicated in Figure 5.2-4 of the CNP UFSAR, the penetration bellows are welded to the fuel transfer tube prior to penetrating through the containment liner, and the bellows do not perform a pressure boundary function. The staff accepted the explanation and concluded that the bellows are neither required to be in scope of license renewal nor subject to aging management. Therefore, RAI 3.5-1 is closed.

RAI 3.5-2

In Item 3.5.1-6 of the LRA, the applicant provided the containment Inservice Inspection Program and the Containment Leakage Rate Testing Program as the AMPs for seals and gaskets related to containment penetrations. For equipment hatches and airlocks at CNP, the staff agrees with the applicant's assertion that the Containment Leakage Rate Testing Program will monitor aging degradation of their seals and gaskets, as they are leak-rate tested after each closing. For other penetrations with seals and gaskets, the staff requested the applicant to provide information regarding the adequacy of Type B LRT frequency to monitor aging degradation of seals and gaskets at CNP.

In response, the applicant stated the following:

> The line item for "Air lock seals" in LRA Table 3.5.2-1 (Page 3.5-39) is the only line item for seals or gaskets in which I&M credits the Containment Leakage Rate Testing Program. The air lock seals line item is also the only line item that refers to Item 3.5.1-6, "Seals, gaskets, and moisture barriers," of LRA Table 3.5.1.

In its subsequent request, the staff pointed out the following:

> Item II A3.3-a (Page # II A3-5) of NUREG-1801 addresses the aging management of seals, gaskets, etc. which are part of the containment pressure boundary, *i.e.* seals and gaskets of equipment hatches, and mechanical & electrical penetrations. If I & M plans to monitor only Air lock seals by means of containment leakage rate testing, then the applicant is requested to provide additional information regarding the aging management of seals and gaskets of equipment hatches, and mechanical and electrical penetration associated with the containment pressure boundary. If I & M intends to use containment leak rate testing program (Type B test of Appendix J) for aging management of these seals and gaskets, the applicant is requested to provide additional information as requested in RAI 3.5-2.

In response, the applicant provided the following information:

> As indicated in LRA Table 3.5.1, the Containment Leakage Rate Testing Program is credited for aging management of seals and gaskets that are part of the containment pressure boundary (*i.e.*, seals and gaskets associated with equipment hatches and with mechanical and electrical penetrations). In LRA Table 3.5.1, equipment and personnel hatches are included in Item Number 3.5.1-4, and seals and gaskets are included in Item Number 3.5.1-6.
>
> Gaskets associated with containment mechanical penetrations are consumables that are replaced each time the bolted joint is disassembled. In addition, such penetrations are tested under the Containment Leakage Rate Testing Program as required by 10 CFR 50, Appendix J. As indicated in LRA Table 3.5.2-1, containment electrical penetrations (which include cable feed-through assemblies) are included in the Containment Leakage Rate Testing Program. The effects of aging on seals and gaskets associated with mechanical and electrical penetrations are also managed by the Containment Leakage Rate Testing Program. LRA Table 3.5.1, Item Number 3.5.1-6, also includes seals and gaskets associated with mechanical and electrical penetrations.
>
> CNP is committed to Option B of 10 CFR 50, Appendix J, for performing containment leakage rate testing. In accordance with Option B, Type B test intervals are limited to 120 months; however, testing is normally performed more

> frequently than every 120 months. Type B testing of CNP mechanical and electrical penetrations is performed at least once every 120 months. Component specific testing frequency is based on the safety significance and historical performance of the penetrations in accordance with Option B of 10 CFR 50, Appendix J.

The clarification emphasizes that the applicant will use the Containment Leakage Rate Testing Program to manage the aging of the seals and gaskets associated with airlock, equipment hatches, and electrical and mechanical penetrations. The clarification also provides the process used in determining the test interval. Based on this information, the staff closed RAI 3.5-2.

RAI 3.5-3

On the subject of degradation of moisture barriers and subsequent liner corrosion, the staff requested the applicant to provide information regarding the operating experience related to the degradation of moisture barriers and the containment liner plate at CNP. The staff also requested the applicant to discuss acceptable liner plate corrosion before it was reinstated to the nominal thickness.

In response, the applicant stated the following:

> In the past, instances of containment liner degradation in the vicinity of the moisture barrier have been identified on both CNP units. However, in only one case was the minimum containment liner thickness found to be less than the acceptance criterion (0.250 inches). In March 1998, an inspection of the Unit 1 containment liner plate identified aging degradation of moisture barrier seal due to poor maintenance and the consequent pitting. The inspection reported the thickness of the steel containment liner to be less than 0.250 inches. The cause of the pitting was determined to have been inadequate installation practices at the time of original construction and a lack of proper maintenance of the seal located between the concrete floor slab and the steel liner. As documented in Unit 1 LER 98-011-02, an analysis of this event determined that the identified steel containment liner pitting would be of no safety significance, as the leaktight integrity of the containment would not be impaired and the as-found liner will continue to fulfill its function as an effective leaktight membrane. The existing seal was removed and the surface on the containment liner plate prepared and coated with new seals applied. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWE, provides the requirements for inservice inspection of containment structures. The requirements include examination, evaluation, repair, and replacement of concrete containment liner plate in accordance with 10 CFR 50.55a. The acceptance criteria for CNP liner plate are in accordance with ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE.

The staff review of LER 98-011-02 indicates that the applicant developed an approach for dealing with the issue of liner corrosion at CNP Units 1 and 2. The staff finds the approach acceptable as it is based on ASME Code, Section XI, Subsection IWE, as incorporated by reference in 10 CFR 50.55a (CNP AMP B.1.15 of the LRA).

In related RAI 3.5-9, the staff requested that the applicant provide additional information related to the degradation of the containment liner plate behind the ice baskets and the method for monitoring the degradation.

By the letter dated November 18, 2004, the applicant provided the following information:

> Permanently installed wall panels separating the liner from the ice baskets prevent ingress of water/moisture between the ice baskets and the liner plate. The liner plate areas behind each unit's ice condenser are inspected as part of inservice inspection through three existing 14-inch diameter circular ports. These inspections are identified in the CNP Containment Inservice Inspection Program Plan, which is part of the aging management program described in LRA Section B.1.15. The inspection results have not indicated the need for augmented inspection.
>
> Other than the inspection port openings, access to the concrete liner behind the permanent ice condenser wall panels would require destructive activities, such as dismantling or modification of the wall panels, removal of divider barrier seal material, or removal/displacement of the ice condenser top deck curtain. Sections of the divider barrier seal material are removed each outage for testing (*i.e.*, test coupons). With the divider barrier seal test coupons removed, a limited view of the liner plate exists through a small gap in the divider barrier steel. I&M implements a recurring task work order to perform a "best effort" visual examination of the liner through this small gap to identify any liner degradation.

In the response, the applicant also indicated that there is a narrow gap at the top of the ice condenser in the area of the top deck doors behind the top deck vent curtain. A limited inspection of the liner behind the ice baskets can be performed; however, it would require a number of potentially destructive activities.

Recognizing the difficulties in conducting these inspections, the staff relies on the applicant's best efforts in detecting degradation of the containment liner plate behind the ice-baskets and its approach to identifying degradation during the period of extended operation. However, the applicant may opt to change its approach if the industry-wide experience related to the degradation of the containment liner (or shell) behind the ice-baskets indicates significant degradation in this area in the future. Therefore, the staff's concern described in RAI 3.5-3 has been resolved.

RAI 3.5-4

In addressing Item 3.5.1-27 in LRA Table 3.5.2-1, for the reinforced concrete structures subjected to elevated temperatures and high humidity (*e.g.*, primary shield walls, pressurizer and steam generator enclosures, and reactor vessel supports), the staff's position is that the "Environment" column should state "elevated temperature." For these structures, the staff requested the that applicant provide the following information:

(a) Provide the method(s) of monitoring temperatures within the primary shield wall concrete, around the reactor vessel, and in the reactor cavity.

(b) If the primary shield wall concrete (or any other structure within CNP containment) is kept below the threshold temperature (*i.e.*, 66 °C (150 °F) by means of air cooling, provide the operating experience related to the performance of the cooling system.

(c) Provide the results of the latest inspection of these structures, in terms of cracking, spalling, and condition of reactor vessel support structures.

In its response, the applicant pointed out that the appropriate pressurizer enclosure component type and environment entries listed in LRA Table 3.5.2-1 on page 3.5-38 are "Pressurizer enclosure (Unit 1)" and "Protected from weather with elevated temperature," respectively. Table 3.0.2 of the LRA defines the environment on page 3.0-10.

In response to the staff request in item (a), the applicant stated the following:

> The primary containment upper and lower compartment average temperature is monitored at various containment building elevations in accordance with applicable technical specifications. However, the temperatures within the primary shield wall concrete, around the reactor vessel, and in the reactor cavity are not directly monitored.

In response to the staff request in item (b), the applicant stated the following:

> The containment ventilation system is designed to maintain a maximum temperature of 100 °F in the containment upper compartment during plant operation, and a maximum temperature of 120 °F in the lower compartment (135 °F inside the primary concrete shield) during plant operation. A search of the corrective action program database for condition reports (CRs) generated over the past five years discovered two CRs that relate to the performance of containment cooling ventilation systems. Both these CRs were resolved as follows:
>
> - A Unit 1 pressurizer enclosure ventilation exhaust fan had significantly lower output than its alternate train fan. A job order adjusted the back draft damper to correct fan performance.
>
> - A pressurizer enclosure ventilation exhaust fan discharge backdraft damper was found to be stuck open with broken linkage. A job order replaced the back draft damper.

The applicant further noted that none of the CRs indicated pressurizer compartment temperatures to be in excess of 66 °C (150 °F).

In response to item (c), the applicant provided a detailed discussion of examinations it performed in November 1999, April 2003, and November 2003, as follows:

Concrete examinations November 1999

The concrete surfaces below the nozzles of the reactor vessel in CNP Unit 2 were examined on November 12, 1999. The methods of examination were visual observation and sounding of the concrete surfaces with a hammer.

The scope of the examination was the horizontal concrete surfaces located at elevation 609' 2" below the Number 2 inlet, and the Number 1 outlet nozzles. Steel reactor supports are located at each nozzle. The junction of the two flanges between the upper and lower portion of the support is approximately 6" above the concrete surfaces observed.

In each location, there was a thin crack parallel to the steel support, approximately 8" to 10" away from the outside of the support. A similar width crack, normal to the support centerline, extended from the center stiffener plate to the parallel crack. The cracks observed were between 1/32" and 1/8" in width at the surface and the width tapered to hairline width within 1/16" of the surface. Solid ringing sounds were produced in response to hammer strikes on all of the accessible surface area. There was no evidence of moisture movement through the cracks or any structural distress or material deterioration of the concrete.

The concrete in question was placed in four 45° sectors, at each support location, between elevations 607' 7" and 609' 2", after the supports were installed. It appeared that the concrete did not support mechanical loads and that its primary function is to fill the space left in the pedestal for installation of the reactor supports. The observed cracks were probably caused by drying shrinkage and were not considered unusual. It did not appear that there has been significant moisture movement through the cracks, and it is doubtful that serious corrosion has resulted in the embedded portion of the support. Therefore, no remedial action was considered necessary for the concrete examined.

Concrete examinations April 2003 and November 2003

A summary of the inspection results of the Unit 1 and Unit 2 biological shield walls in the Containment Buildings is provided below. These inspections were performed during the U1C19 (November 2003) and U2C14 (April 2003) refueling outages.

Starting at elevation 598' (which is about 12 feet below the vessel supports) and going upward, both wall exterior faces are in very good condition. The walls exhibited a few, limited, scattered, hairline cracks. The longest hairline cracks were no more than ten feet long. Almost all of the observed cracks were between elevation 598' and about 608' (between the floor and a horizontal construction joint). There was very little indication of efflorescence (calcium deposits) in these cracks. There were no indications of any spalling. The condition of the walls (very limited cracking) can be attributed to their extremely robust design. The walls at this location are approximately seven feet thick, with several layers of reinforcing steel bars.

The staff finds the applicant's approach in monitoring these structures acceptable, as (1) the applicant has adequate controls that would indicate the malfunctioning of fans and coolers that control the temperature around the reactors and pressurizer enclosures, and (2) the applicant inspects the condition of the concrete structures around the reactor and in the pressurizer enclosure that will maintain the intended functions of these structures during the period of extended operation. Therefore, the staff's concern described in RAI 3.5-4 has been resolved.

Aging Management Programs

The staff reviewed Table 3.5.2-1 of the LRA, which summarized the results of AMR evaluations in the SRP-LR for the containment structures component groups.

In the LRA, the applicant stated that it manages the loss of material for stainless steel fuel transfer tube penetration component types exposed to borated water using the Inservice Inspection—ASME Section XI, Subsection IWE and Containment Leakage Rate Testing Programs. The staff reviewed these programs and documents its evaluations in Sections 3.0.3.2.7 and 3.0.3.1 of this SER, respectively. Because this is consistent with the GALL Report recommendation for components with the same material, environment, and aging effect, the staff finds this to be acceptable.

In the LRA, the applicant stated that it manages the loss of material for galvanized steel ice baskets exposed to borated ice using the Structures Monitoring—Ice Basket Inspection Program. The staff reviewed this program and documents its evaluation in Section 3.0.3.3.12 of this SER. On the basis of the operating experience and root causes identified for corrective work, the staff concluded that this is acceptable.

In the LRA, the applicant stated that it manages the loss of material for the galvanized steel ice condenser lattice frame, carbon steel ice condenser lower support structure, and carbon steel ice condenser turning vanes exposed to borated ice using the Structures Monitoring—Structures Monitoring Program. The staff documents its evaluation of this program in Section 3.0.3.2.12 of this SER. The applicant also stated that it manages the loss of material of the stainless steel ice condenser wall duct panels component type exposed to borated ice using the same program. On the basis that the Structures Monitoring Program is consistent with GALL AMP XI.S6 and adequately manages the loss of material for these components, the staff finds this acceptable.

In the LRA, the applicant stated that it manages loss of material for carbon steel reactor vessel supports (water cooled) exposed to treated water using the Water Chemistry Control—Closed Cooling Water Chemistry Control and the Inservice Inspection—ASME Section XI, Subsection IWF Programs. The staff reviewed these programs and documents its evaluations in Sections 3.0.3.2.16 and 3.0.3.1 of this SER, respectively. Because these programs are consistent with the GALL Report recommendation for other components with the same material, environment, and aging effect, the staff finds this to be acceptable.

The applicant stated in the LRA that it identified no aging effects for stainless steel components exposed to air (protected from weather), including removable gate (bulkhead), seal table, and sump screens component types. The applicant identified no aging effects for galvanized steel sump screens and associated framing exposed to air (protected from weather). The GALL Report does not identify air as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoor, or in an air-conditioned enclosure or room). Significant corrosion of carbon and LAS requires an electrolytic environment and a simultaneous presence of oxygen and moisture. Without the presence of the aggressive environment, LAS components will experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concludes that metal in a dry air environment has no AERMs.

In the LRA, the applicant stated that it manages loss of material for cadmium-plated steel threaded fasteners (ice basket) exposed to borated ice using the Ice Basket Inspection Program. On the basis of the operating experience and root causes identified for corrective work, the staff concludes that this is acceptable.

In the LRA, the applicant stated that it manages reinforced concrete protected from the weather using the Structures Monitoring Program and the Inservice Inspection—ASME Section XI, Subsection IWL Program for the containment base slab foundation component type. The applicant also stated that it manages reinforced concrete exposed to weather using the Structures Monitoring and the Inservice Inspection—ASME Section XI, Subsection IWL Programs for the containment dome and wall, as well as the exhaust dome and duct component types. On the basis that the programs that manage the aging of these components (same materials and environments) are consistent with the GALL Report, the staff finds this to be acceptable.

In the LRA, the applicant stated that it manages reinforced concrete protected from the weather using the Structures Monitoring Program for the containment operating deck, the crane wall (upper), ice condenser end walls, fuel transfer canal walls and floodup overflow structure, lower containment concrete walls and floor slabs, reactor cavity missile blocks, regenerative heat exchanger room walls, and steam generator enclosures. On the basis that the program that manages the aging of these components (same materials and environments) is consistent with the GALL Report, the staff finds this to be acceptable.

RAI 3.5.3-1

In the LRA, the applicant stated that it manages the loss of material, cracking, and the change of material properties of concrete exposed to borated ice for ice condenser support slab and ice condenser wear slab using the Structures Monitoring Program. The staff could not confirm the applicability of the precedent cited. By letter dated August 20, 2004, in RAI 3.5.3-1, the staff asked the applicant to clarify whether the ice condenser support slab and ice condenser wear slab are accessible for direct monitoring. If not, the staff asked the applicant to describe specifically how it will manage the associated aging effects.

By letter dated September 2, 2004, the applicant responded to RAI 3.5.3-1, stating that the ice condenser wear slab is accessible for inspection (direct monitoring) from inside the ice condenser during refueling outages. The ice condenser support slab is accessible for inspection (direct monitoring) from below in various rooms within the containment annulus area (*i.e.*, outside the crane wall).

On the basis of its review of the response to RAI 3.5.3-1, the staff finds the applicant's response acceptable because direct monitoring is possible for the ice condenser wear slab and ice condenser support slab. The staff finds that the applicant has demonstrated that it will adequately manage the loss of material, cracking, and change of material properties of concrete exposed to borated ice for the ice condenser support slab and the ice condenser wear slab using the Structures Monitoring Program, so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it manages cracking and the change in material properties of elastomers protected from weather for removable gate bulkhead seals using the Structures Monitoring—Divider Barrier Seal Inspection Program. The staff reviewed this program and documents its evaluation in Section 3.0.3.3.11 of this SER. The staff finds that this program adequately manages the cracking aging effect through visual examination of the seal. However, the staff asked the applicant to identify how it detects changes in material properties. During the audit, the applicant responded that it meant the phrase "change in material properties" to include a visual inspection that ensures the absence of apparent deterioration (cracks or defects). By letter dated April 23, 2004, the applicant reiterated this position in its clarification to the Structures Monitoring—Divider Barrier Seal Inspection Program question.

Because the applicant addressed cracking separately, and because it did not address material properties that may affect the performance of seals (*e.g.*, hardening and embrittlement), the staff did not consider this issue resolved. By letter dated August 20, 2004, in RAI B.1.34-1, the staff asked the applicant to provide a basis for concluding that degradation (*e.g.*, hardening and embrittlement) will be apparent before the intended function is challenged. Otherwise, the staff asked the applicant to provide a technical basis for concluding that the elastomeric divider barrier will continue to perform its design function despite changes in material properties that may not be visible.

The staff clarified, in an earlier telephone conversation with the applicant, that the elastomeric pressure seals in question are the penetration seals installed around containment penetrations and openings through the divider barrier. The applicant identified that it inspects the main divider barrier seals and replaces them based on their condition, in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.9, so that these are not subject to AMR. Additionally, the applicant identified that it visually inspects the divider barrier personnel access door and equipment hatch seals before containment closure each outage, in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.5, so that these are also not subject to an AMR.

By letter dated September 2, 2004, in its response to RAI B.1.34-1, the applicant stated that it identified the aging management approach for the divider barrier penetration seals in LRA Table 3.5.2-1, page 3.5-40, under the component type "removable gate (bulkhead) seals," and in LRA Table 3.5.2-5, page 3.5-66, under the component type "divider barrier penetration seals." These elastomeric seals are subject to cracking and change in material properties aging effects, which results in thermal exposure and ionizing radiation aging mechanisms. The noteworthy effects of these aging mechanisms are elongation, cracking, swelling, and melting. Cracking, swelling, and melting are readily identifiable by visual inspection. The applicant stated that visual inspections would observe these aging effects as abnormalities indicative of material degradation before aging would challenge the intended function of the seals.

On the basis of its review of the applicant's response to RAI B.1.34-1, the staff finds that the reply is acceptable because visual inspection will adequately monitor changes in material properties of the penetration divider barrier seals so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion

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 containment isolation system components that are not addressed by the GALL Report. The intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.5.2.3.2 Auxiliary Building

Summary of Technical Information in the Application

In Section 3.5.2.1.2 of the LRA, the applicant identified the materials, environments, and AERMs in the auxiliary building. The applicant identified the following AMPs that will manage the aging effects for the auxiliary building components:

- Boric Acid Corrosion Prevention Program
- Systems Testing Program
- Structures Monitoring—Structures Monitoring Program
- Structures Monitoring—Crane Inspection Program
- Structures Monitoring—Masonry Wall Program
- Water Chemistry Control Program

In Table 3.5.2-2 of the LRA, the applicant summarized the AMRs for the auxiliary building components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

The staff reviewed Table 3.5.2-2 of the LRA, which summarizes the results of AMR evaluations in the SRP-LR for the auxiliary building component groups.

In the LRA, the applicant proposed to manage loss of material in the galvanized steel EDG air intake missile shield grating exposed to weather using the Structures Monitoring Program. The staff finds that the Structures Monitoring Program is acceptable for managing loss of material because the applicant will perform visual inspections on surfaces for any sign of aging degradation. On the basis of its review, the staff finds that the applicant has identified the appropriate aging effect for galvanized steel components in an exposed environment and thus adequately manages this aging effect.

In the LRA, the applicant stated that it identified no aging effects for stainless steel structures exposed to air, including the new fuel storage racks. The GALL Report does not identify air as an environment for this structure and material.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments referred to are typical of ambient air (*e.g.*, under a shelter, indoor, or in an air-conditioned enclosure or room). Wrought austenitic stainless steels and CASS are not susceptible to significant general corrosion that would affect the intended functions of components. Therefore, the staff concludes that stainless steel in an air environment that is protected from weather has no AERMs.

In the LRA, the applicant identified no aging effect for Transite exposed to weather, but it uses the Structures Monitoring Program to manage its aging. The GALL Report identifies no aging effect for this material and environment. This is consistent with industry experience. On that basis the staff finds the use of the Structures Monitoring Program to be acceptable.

In the LRA, the applicant stated that it manages reinforced concrete using the Structures Monitoring Program evaluated in Section 3.0.3.2.12 of this SER. This applies to reinforced concrete both protected from weather and exposed to weather (above- and below- grade) for the electrical tunnel, exterior walls above and below grade, floor slabs, the fuel transfer canal, the foundation, interior walls, internal flood curbs, the main steamline enclosure, the roof, spent fuel pit walls and slab, and the sump. On the basis that the program managing the aging of these components (same materials and environments) is consistent with the GALL Report, the staff finds this to be acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects and the AMPs credited to manage the aging effects for the auxiliary building components that are not addressed by the GALL Report, so that the intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.5.2.3.3 Turbine Building and Screenhouse

Summary of Technical Information in the Application

In Section 3.5.2.1.3 of the LRA, the applicant identified the materials, environments, and AERMs subject to aging in the turbine building and screenhouse. The applicant identified the following programs that manage the AERMs for the turbine building and screenhouse components:

- Structures Monitoring—Structures Monitoring Program
- Structures Monitoring—Masonry Wall Program

In Table 3.5.2-3 of the LRA, the applicant summarized the AMRs for the turbine building and screenhouse components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

The staff reviewed Table 3.5.2-3 of the LRA, which summarizes the results of AMR evaluations in the SRP-LR for the turbine building and screenhouse component groups.

In the LRA, the applicant stated that it manages the loss of material for galvanized steel components, including intake corrugated piping and screenhouse forebay bar grille and base, exposed to raw water, using the Structures Monitoring Program. The staff finds that galvanized steel components in a raw-water outdoor environment are susceptible to the loss of material. On the basis of industry operating experience of galvanized steel components exposed to a raw-water outdoor environment, the staff finds that the loss of material is an applicable aging effect and is adequately managed by the Structures Monitoring Program.

In the LRA, the applicant stated that it manages reinforced concrete both protected from weather and exposed to weather (above and below grade) using the Structures Monitoring Program for the 12-inch concrete wall, essential motor control center walls, the ESW pump room, the AFW pump room (walls, floor, and ceiling), foundation mat (turbine building) screenhouse exterior walls (above grade), and the superstructure steel column concrete encasing. On the basis that the program that manages the aging of these components (same materials and environments) is consistent with the GALL Report, the staff finds this to be acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects and the AMPs credited to manage the aging effects for the turbine building and screenhouse components that are not addressed by the GALL Report, so that the intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.5.2.3.4 Yard Structures

Summary of Technical Information in the Application

In Section 3.5.2.1.4 of the LRA, the applicant identified the materials, environments, and AERMs subject to aging for the yard structures components. The applicant identified the following program that manages the AERMs for the yard structures components:

- Structures Monitoring—Structures Monitoring Program

In Table 3.5.2-4 of the LRA, the applicant summarized the AMRs for the yard structures components and identified which AMRs it considered to be not consistent with or not addressedthe GALL Report.

Staff Evaluation

The staff reviewed Table 3.5.2-4 of the LRA, which summarized the results of AMR evaluations in the SRP-LR for the yard structures groups.

In the LRA, the applicant stated that it manages the loss of material for the galvanized steel tower, Unit 2 power delivery structure (exposed to weather) using the Structures Monitoring Program. The staff finds that galvanized steel structures in outdoor environments are susceptible to loss of material. On the basis of industry operating experience of galvanized steel structures exposed to an outdoor environment, the staff finds that the loss of material is an applicable aging effect, which the Structures Monitoring Program adequately manages.

In the LRA, the applicant stated that it manages reinforced concrete exposed to weather (above and below grade) using the Structures Monitoring Program for the FP pump house walls and foundation, gas bottle storage tank foundation, roadway, security diesel generator room, switchyard control house, tank area pipe tunnel (condensate storage, refueling water storage, and EDG piping tunnel), RWST foundation, CST foundation, FP water storage tank foundation, PW storage tank foundation, Unit 1 power delivery to switchyard tower, startup transformer pedestals, and the trench from switchyard to startup transformers (duct bank). On the basis that the program that manages the aging of these structures (same material and environments) is consistent with the GALL Report, the staff finds this to be acceptable.

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects and the AMPs credited with managing the aging effects for the yard structures components that are not addressed by the GALL Report, so that the intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.5.2.3.5 Structural Commodities

Summary of Technical Information in the Application

In Section 3.5.2.1.5 of the LRA, the applicant identified the materials, environments, and AERMs subject to aging for the structural commodities. The applicant identified the following programs that manage the AERMs for the structural commodities components:

- Boric Acid Corrosion Prevention Program
- Containment Leakage Rate Testing Program
- Fire Protection Program

- Inservice Inspection—ASME Section XI, Subsection IWE Program
- Inservice Inspection—ASME Section XI, Subsection IWF Program
- Structures Monitoring—Structures Monitoring Program
- Structures Monitoring—Crane Inspection Program
- Structures Monitoring—Divider Barrier Seal Inspection Program
- Water Chemistry Control Program

In Table 3.5.2-5 of the LRA, the applicant summarized the AMRs for the structural commodities components and identified which AMRs it considered to be not consistent with or not addressed in the GALL Report.

Staff Evaluation

The staff reviewed Table 3.5.2-5 of the LRA, which summarized the results of AMR evaluations in the SRP-LR for the structural commodities groups.

The staff evaluated all other AMRs assigned to it in LRA Tables 3.5.2-1 through 3.5.2-5. The staff finds them to be acceptable.

In the LRA, the applicant stated that it manages the loss of material for galvanized steel components, including base plates, embedded unistrut, cable trays, and conduits (exposed to weather) using the Structures Monitoring Program. The staff finds that galvanized steel components in an outdoor environment are susceptible to the loss of material. On the basis of industry operating experience of galvanized steel components exposed to an outdoor environment, the staff finds that the loss of material is an applicable aging effect, which the Structures Monitoring Program adequately manages.

In the LRA, the applicant stated that it manages the loss of material for aluminum roof flashing exposed to weather using the Structures Monitoring Program. 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 roof flashing.

In the LRA, the applicant stated that it manages the loss of material for the carbon steel equipment hatch and personnel access openings threaded fasteners (protected from weather) using the Inservice Inspection—ASME Section XI, Subsection IWE and Containment Leakage Rate Testing Programs. On the basis that the programs that manage this aging effect are consistent with the GALL Report for the same material and environment, the staff finds that the applicant adequately manages this component type.

In the LRA, the applicant stated that it manages cracking and the loss of material for stainless steel SFP fasteners exposed to borated water using the Water Chemistry Control—Primary and Secondary Water Chemistry Control Program. The staff reviewed this program and documents its evaluation in Section 3.0.3.2.15 of this SER. Based on its review and industry operating experience, the staff finds the aging effects to be acceptable, and the program is adequate to manage them.

In the LRA, the applicant identified no aging effect for Transite exposed to weather, but it used the Structures Monitoring Program to manage aging. On the basis of industry experience with this material, the staff finds it acceptable to use the Structures Monitoring Program.

In the LRA, the applicant stated that it manages reinforced concrete, both protected from and exposed to weather, using the Structures Monitoring Program for flood curbs, hatches, support pedestals, and trenches (for pipe and cable). On the basis that the program that manages the aging of these SCs (same materials and environments) is consistent with the GALL Report, the staff finds this to be acceptable.

RAI 3.5.3-2

In the LRA, the applicant stated that it manages pyrocrete protected from weather using the Fire Protection Program. The staff reviewed this program and documents its evaluation in Section 3.0.3.2.5 of this SER. During the audit, the staff noted that separation, cracking, and loss of material are applicable aging effects for pyrocrete. By letter dated August 20, 2004, in RAI 3.5.3-2, the staff asked the applicant to identify how the Fire Protection Program manages the aging effects of separation, cracking, and loss of material, or justify why these aging effects are not applicable.

By letter dated September 2, 2004, in its response to RAI 3.5.3-2, the applicant stated that during the Fire Protection Program inspections, it monitors pyrocrete by visual inspection for obvious degradation such as flaking, cracking, separation, and loss of material.

On the basis of its review of the applicant's response to RAI 3.5.3-2, the staff finds that the applicant will adequately manage the aging effects of flaking, cracking, separation, and loss of material using the Fire Protection Program so that the intended functions will be consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it manages cracking and the change of material properties for elastomers of the building pressure boundary sealant, floor plugs, and penetration seals protected from weather using the Structures Monitoring Program. The staff finds the applicant's approach to evaluating the applicable aging effects for elastomers in structures outside the containment to be reasonable and acceptable. The staff concludes that the applicant properly identified the aging effects for elastomers in these structures.

In the LRA, the applicant stated that it manages cracking and the change in material properties of the divider barrier penetration seal elastomers (protected from weather) using the Structures Monitoring—Divider Barrier Seal Inspection Program. The staff reviewed this program and documents its evaluation in Section 3.0.3.3.11 of this SER. In addition, in the LRA, the applicant proposed to manage changes in material properties by visual examination. The staff asked the applicant to further justify how a visual examination can detect changes in material properties.

By letter dated August 20, 2004, in RAI B.1.34-1, the staff asked the applicant to provide a basis for concluding that degradation (*e.g.*, hardening and embrittlement) will be apparent before the intended function is challenged. Otherwise, the staff asked the applicant to provide a technical basis for concluding that the elastomeric divider barrier will continue to perform its design function despite changes in material properties that may not be visible.

The staff clarified, in an earlier telephone conversation with the applicant, that the elastomeric pressure seals in question are the penetration seals installed around containment penetrations and openings through the divider barrier. The applicant identified that it inspects the main divider barrier seals and replaces them based on their condition in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.9, so that these are not subject to AMR. Additionally, the applicant identified that it visually inspects the divider barrier personnel access door and equipment hatch seals before containment closure each outage, in accordance with CNP Technical Specification Surveillance Requirement 4.6.5.5, so that these are also not subject to an AMR.

By letter dated September 2, 2004, in its response to RAI B.1.34-1, the applicant stated that it identified the aging management approach for the divider barrier penetration seals in LRA Table 3.5.2-1, page 3.5-40, under the component type "removable gate (bulkhead) seals," and in LRA Table 3.5.2-5, page 3.5-66, under the component type "divider barrier penetration seals." These elastomeric seals are subject to cracking and change in material properties aging effects, which result in thermal exposure and ionizing radiation aging mechanisms. The noteworthy effects of these aging mechanisms are elongation, cracking, swelling, and melting. Cracking, swelling, and melting are readily identifiable by visual inspection. The applicant stated that visual inspections would observe these aging effects as abnormalities indicative of material degradation before aging would challenge the intended function of the seals.

On the basis of its review of the response to RAI B.1.34-1, the staff finds that the applicant's response is acceptable because visual inspection will adequately monitor changes in material properties of the penetration divider barrier seals so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In the LRA, the applicant stated that it manages the joint elastomer at seismic gaps protected from weather using the Structures Monitoring Program. During the audit, the staff asked the applicant to justify the basis for its conclusion that the elastomer will not harden. The applicant responded that the function of this elastomer is to prevent debris from entering the gap. Degradation by hardening of joint elastomer at seismic gaps would not prevent the seismic gap from performing its intended function. On the basis that the Structures Monitoring Program will detect the absence of elastomer material, the staff finds that the Structures Monitoring Program adequately manages aging of the joint elastomer at seismic gaps.

In the LRA, the applicant stated that it manages cracking and change of material properties for roof elastomers exposed to the weather using the Structures Monitoring Program. 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 concluded that the applicant properly identified the aging effects for elastomers in these structures.

The staff reviewed all other AMRs in Tables 3.5.2-1 through 3.5.2-5 of the LRA. The staff finds them to be acceptable.

<u>Conclusion</u>

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects and the AMPs credited to manage the aging effects for the structural commodities components that are not addressed by the GALL Report. The intended functions will be 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 the UFSAR Supplement adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.5.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the structures and component supports, as well as the commodity groups that are within the scope of license renewal and subject to an AMR, so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) components associated with the following commodity groups:

- insulated cables and connections
- switchyard bus
- high-voltage insulators

3.6.1 Summary of Technical Information in the Application

In Section 3.6 of the LRA, the applicant provided the results of the AMR of the electrical and I&C components listed in Table 3.6-1 of the LRA. The applicant also listed the materials, environments, AERMs, and AMPs associated with each commodity group.

In Table 3.6-1, "Summary of the Aging Management Programs for the Electrical Components Evaluated in Chapter VI of NUREG-1801," of the LRA, the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the electrical and I&C components and component types. In Section 3.6.2.2 of the LRA, the applicant provided information concerning Table 3.6-1 components for which the GALL Report recommends further evaluation.

3.6.2 Staff Evaluation

The staff reviewed Section 3.6 of the LRA to understand the applicant's review process and to determine whether the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the electrical and I&C components that are within the scope of license renewal and subject to an AMR. This will verify 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 performed an audit to confirm the applicant's claim that certain identified AMRs are consistent with the staff-approved AMRs in the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL AMRs. Section 3.6.2.1 of this SER summarizes the staff's audit findings.

The staff also audited those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's additional evaluations are consistent with the acceptance criteria in Section 3.6.3.2 of the SRP-LR. Section 3.6.2.2 of this SER summarizes the staff's audit findings.

Section 3.6.2.3 contains the staff's evaluation of AMRs that are specific to the electrical and I&C components. This section also contains evaluation of the adequacy of aging management for components in each system in electrical and I&C system group. The review included evaluating whether the applicant identified all plausible aging effects and listed aging effects that are appropriate for the combination of materials and environments specified.

The staff conducted a technical review of the remaining AMRs that were not consistent with or addressed by the GALL Report. The review included evaluating whether the applicant identified all plausible aging effects and listed the appropriate aging effects for the combination of materials and environments specified. Section 3.6.2.3 of this SER documents the staff's review findings.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they adequately describe the programs credited with managing or monitoring aging for the electrical and I&C components.

Table 3.6-1 below summarizes 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 for Electrical and Instrumentation and Controls Components 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 (Item Number 3.6.1-1)	Degradation due to various aging mechanisms	Environmental qualification of electric components	TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.6.2.2.1)

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 (Item Number 3.6.1-2)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure caused by thermal/ thermoxidative degradation of organics, radiolysis and photolysis (ultraviolet- 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	Non-EQ Insulated Cables and Connections Program (B.1.22)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (Item Number 3.6.1-3)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	AMPs for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	Non-EQ Instrumentation Circuits Test Review Program (B.1.21)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Inaccessible medium voltage (2 kV to 15 kV) cables not subject to 10 CFR 50.49 EQ requirements (Item Number 3.6.1-4)	Formation of water trees; localized damage leading to electrical failure (breakdown of insulation) caused by moisture intrusion and water trees	AMP for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	Non-EQ Inaccessible Medium-Voltage Cable Program (B.1.20)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Electrical conductors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage (Item Number 3.6.1-5)	Corrosion of connector contact surfaces caused by intrusion of borated water	Boric acid corrosion prevention	Boric Acid Corrosion Prevention Program (B.1.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

The staff's review of the electrical and I&C components followed one of several approaches. One approach, documented in Section 3.6.2.1 of this SER, involves the staff's review of the AMR results for the electrical and I&C components that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in Section 3.6.2.2 of this SER, involves the staff's review of the AMR results for the electrical and I&C components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in Section 3.6.2.3 of this SER, involves the staff's review of the AMR results for the electrical and I&C components that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. Section 3.0.3 of this SER documents the staff's review of AMPs that are credited with managing or monitoring aging effects of the structures and component supports.

3.6.2.1 Aging Management Evaluations That Are Consistent with the GALL Report, for Which No Further Evaluation Is Required

Summary of Technical Information in the Application

In Section 3.6.2.1 of the LRA, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the electrical and I&C components:

- Boric Acid Corrosion Prevention Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Instrumentation Circuits Test Review Program
- Non-EQ Insulated Cables and Connections Program

Staff Evaluation

In Table 3.6.2-1 of the LRA, the applicant provided a summary of AMRs for the electrical and I&C components and identified which AMRs it considered to be consistent with the GALL Report. The applicant provided a note for each AMR line item. The notes describe the alignment of the information in the tables with the information in the GALL Report. The staff audited those AMRs with notes A through E, where applicable, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant could not find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component is applicable to the component under review. The staff verified whether it had reviewed and accepted the identified exceptions to the GALL AMPs. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but the applicant has credited a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA and program basis documents, which are available at the applicant's engineering office. On the basis of its audit and review, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant identified the applicable aging effects and that they are appropriate for the combination of materials and environments listed.

3.6.2.1.1 Non-EQ Inaccessible Medium-Voltage Cable

<u>Summary of Technical Information in the Application</u>

Table 3.6.1 of the LRA presents the AMR results for non-EQ inaccessible medium-voltage cables. The applicant used the GALL Report format to present its AMR of inaccessible medium-voltage cables requiring aging management.

The applicant identified the following aging effects for non-EQ inaccessible medium-voltage cables:

- formation of water trees
- localized damage leading to electrical failure (breakdown of insulation) caused by moisture intrusion and water trees

The applicant credited the Non-EQ Inaccessible Medium-Voltage Cable Program with managing the identified aging effects for non-EQ inaccessible medium-voltage cables.

A description of the AMP appears in Appendix B to the LRA.

Staff Evaluation

The staff reviewed the information in LRA Table 3.6.1 for non-EQ inaccessible medium-voltage cables. On the basis of its review, the staff concludes that the aging effects identified for the aforementioned cables are consistent with the aging effects evaluated in the GALL Report and are therefore acceptable.

The staff also reviewed the AMP presented in Section B.1.20 of Appendix B to the LRA, which is credited with managing the effects for non-EQ inaccessible medium-voltage cables. The applicant stated that the Non-EQ Inaccessible Medium-Voltage Cable Program (CNP AMP B.1.20) will apply to non-EQ inaccessible medium-voltage cables and will be consistent with GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Requirements."

The staff reviewed seven program elements contained in the AMP and associated bases documents against GALL AMP XI.E3 for consistency.

RAI 3.6-3

In a letter dated May 6, 2004, the staff issued RAI 3.6-3, requesting the applicant to clarify the following:

> In response to an audit team's question on inaccessible medium voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with applied voltage, it was stated that the AMP for inaccessible medium voltage cables will test the cables as well as inspect for water in the manholes. It was also stated that inspection of water in the manholes associated with the GALL XI.E3 AMP would be performed every 10 years. The frequency to inspect for water in manholes every ten years may be too long. Justify the frequency of inspecting manholes for water every 10 years. In addition, provide your current criteria for inspecting manholes for water.

In a letter dated June 8, 2004, the applicant stated that the Non-EQ Inaccessible Medium-Voltage Cable Program will be consistent with GALL AMP XI.E3. GALL AMP XI.E3, Section 2, states the following:

> Periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. Medium-voltage cables for which such actions are taken are not required to be tested since operating experience indicates that prolonged exposure to moisture and voltage are required to induce this aging mechanism.

> This section implies that if periodic actions are not taken to prevent cable exposure to significant moisture, testing is required. The Non-EQ Inaccessible Medium-Voltage Cable Program will require testing of all cables included in the program. The frequency of inspections for water is relevant only if it provides reasonable assurance that the cables are not exposed to significant moisture and therefore do not require testing. Since testing is to be performed regardless

> of inspection results, the inspection frequency is not relevant. The proposed testing frequency in the AMP is consistent with GALL AMP XI.E3 for cables that are exposed to significant moisture.

The staff concludes that, since the Non-EQ Inaccessible Medium-Voltage Cable Program will require testing of all cables included in the program, the above response is acceptable. Therefore, the staff's concerns described in RAI 3.6-3 are resolved.

RAI 3.6-4

The staff was also concerned about inaccessible medium-voltage cables that run in sealed conduits from transformers TR201 AB to bus 2A which are not subject to any AMP. In a letter dated May 6, 2004, the staff issued RAI 3.6-4 asking the applicant to clarify the following:

> In response to audit team's question on inaccessible medium voltage cables, it was stated that the cables from transformer TR 201 AB to bus 2A run in conduits that are sealed on both ends and have been inspected for water and that the lack of water precludes any aging mechanisms on the cables that would make them subject to an AMP. It is not clear to the staff how often these seals are inspected for water damage and how often they are replaced. An AMP would be needed to assure that the seals remain intact to prevent intrusion of water in the conduits. Please provide a description of the AMP that will be relied upon to require periodic inspections of these seals or provide justification for not having an AMP. In addition, describe how the cables from (1) start-up transformers TR 201 CD, 101 AB, and 101 CD to the safety buses and (2) from transformers TR4 and TR5 to the start-up transformers, are routed.

In a letter dated June 8, 2004, the applicant responded that it previously determined the cables associated with the sealed conduits are not subject to aging effects, because they are not exposed to significant moisture. The applicant stated, however, that it will add these cables to the list of those subject to GALL AMP XI.E3. Consistent with the response to RAI 3.6-3, the applicant will test all of the cables included in LRA Section B.1.20. These cables will not require inspection for the presence of significant moisture. Therefore, inspection of the seals will not be relevant since the cables will be tested. An AMP for conduit seal inspections is not required.

With regard to the routing of cables from the transformers to the safety buses, the applicant stated that a combination of switchyard bus and insulated feeder cables, which are not installed underground, connect the Unit 1 reserve auxiliary transformers, TR101AB and TR101CD, and safety buses 1A, 1B, 1C, and 1D. Cables in underground conduits encased in a duct bank which is sealed on both ends connect the Unit 2 reserve auxiliary transformers, TR201AB and TR201CD, and safety buses 2A, 2B, 2C, and 2D.

Based on the above, the staff concludes that the addition of cables in underground conduits to the list of cables subject to GALL AMP XI.E3 testing requirements satisfies its concern. Therefore, the staff's concerns described in RAI 3.6-4 are resolved.

RAI 3.6-5

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 are adequate. In a letter dated May 6, 2004, the staff issued RAI 3.6-5, stating that the UFSAR Supplement description in the LRA for the non-EQ cable AMPs does not adequately describe the program, as required by 10 CFR 54.21(d). The description of the UFSAR Supplement for aging management of electrical and I&C components should be consistent with Table 3.6-2 of the SRP-LR. The staff asked the applicant to submit a revised UFSAR Supplement that is consistent with SRP-LR to satisfy 10 CFR 54.21(d).

In letters dated June 8 and September 2, 2004, the licensee submitted revised program descriptions for UFSAR Supplements for the AMPs credited with managing aging in electrical and I&C system components. However, the revised UFSAR Supplement for GALL AMP XI.E2 does not describe the AMP that will manage those instrument cables that are disconnected during instrument calibration.

By letter dated October 18, 2004, the applicant stated that it will include testing of instrumentation cables that are disconnected during calibration and revised the Non-EQ Instrumentation Circuits Test Review Program description for the UFSAR as follows:

> The Non-EQ Instrumentation Circuits Test Review Program will manage aging effects for electrical cables that:
>
> 1. Are not subject to the environmental qualification requirements of 10 CFR 50.49, and
>
> 2. Are used in instrumentation circuits with sensitive, high-voltage, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture.
>
> An adverse localized environment is defined as being significantly more severe than the specified service environment for the cable. This program will detect aging effects by reviewing calibration or surveillance results for components within the program scope. A proven cable test for detecting insulation deterioration on in-scope instrumentation cables that are disconnected during calibration will be performed at a frequency determined by engineering evaluation, but will not be less than once per ten years. The Non-EQ Instrumentation Circuits Test Review Program will be implemented prior to the period of extended operation.

This is Commitment # 13 in Appendix A of this SER.

Based on its review, the staff concludes that the revised UFSAR Supplements provide an adequate summary description of the revised non-EQ cable AMPs and are acceptable. Therefore, the staff's concern described in RAI 3.6-5 is resolved.

The staff conducted an audit of the information provided in the LRA and program basis documents, which are available at the applicant's engineering office. On the basis of its audit, the staff finds that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff finds that the applicant identified the applicable aging effects and that they are appropriate for the combination of materials and environments listed.

On the basis of its audit, the staff concludes that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects, and the AMPs credited with managing the aging effects, for inaccessible medium-voltage cables. Therefore, the intended functions will be 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 the UFSAR Supplement given in the applicant's revision dated October 18, 2004, adequately describes the AMPs credited with managing aging in these components, as required by 10 CFR 54.21(d).

3.6.2.1.2 Staff RAIs Pertaining to Recent Operating Experience and Emerging Issues

Because the NRC issued the GALL Report and SRP-LR in July 2001, these documents do not reflect the most current recommendations for managing certain aging effects that have been the subject of recent operating experience or the topic of an emerging issue. As a result, the staff issued RAIs to determine how the applicant proposes to address these items for license renewal. The following documents the applicant's responses to these RAIs and the staff's evaluations of the responses.

Staff Evaluation

The NRC issued proposed ISG-15,"Revision of Generic Aging Lessons Learned (GALL) Aging Management Program (AMP) XI.E2, 'Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,'" to incorporate lessons learned since the GALL Report was first issued. The current GALL AMP XI.E2 relies on a routine calibration test performed as part of plant technical specification requirements to identify the existence of aging degradation for the electrical cables used in radiation monitoring and nuclear instrumentation circuits. For those plants for which technical specification requirements do not require calibration testing of the instrumentation loops, this revision provides that an applicant may use a proven cable test for detecting deterioration of the insulation system (such as insulation resistance tests, time-domain reflectometry tests, or other testing judged to be effective in determining cable insulation condition).

The CNP program for the management of aging effects of electrical cables not subject to 10 CFR 50.49 requirements used in instrumentation circuits will be the Instrumentation Circuit Test Review Program. This program will be consistent with, but include the following exception to, GALL AMP XI.E2:

Rather than perform the reviews at normal calibration frequency specified in the Technical Specifications, the first reviews will be performed before the period of extended operation and every 10 years thereafter. Calibrations or surveillances that fail the acceptance criteria will be reviewed at the time of the calibration or surveillance.

The staff concludes that the above program is consistent with proposed ISG-15.

RAI 3.6-2

In a letter dated May 6, 2004, the staff issued RAI 3.6-2:

> With regard to non-EQ cables sensitive to a reduction in insulation resistance, please confirm consistency with the proposed ISG-15, Revision of Generic Aging Lessons Learned (GALL) Aging management Program (AMP) XI.E2,"Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

In a letter dated June 8, 2004, the applicant responded to RAI 3.6-2, stating the following:

> The exception to NUREG-1801, Section XI.E2, in LRA Appendix B, Section B.1.21, states that, "The first reviews will be performed before the period of extended operation and every 10 years thereafter. Calibrations or surveillances that fail to meet the acceptance criteria will be reviewed at the time of the calibration or surveillance." The intent of this exception is in agreement with the mark-up of ISG-15 provided to the NRC in the referenced NEI letter dated December 15, 2003. The NRC has not yet issued a formal response to these industry comments. Therefore, it is the intent of this program to be consistent with NUREG-1801, Section XI.E2 with the stated exception, which is consistent with the draft of ISG-15 provided in the referenced NEI letter. Other elements of the Non-EQ Instrumentation Circuits Test Review Program are consistent with ISG-15.

In addition, the staff asked the applicant if any instrumentation cables at CNP are disconnected for the purpose of instrument calibration. By letter dated October 18, 2004, the applicant responded by stating the following:

> CNP has instrumentation cables within the scope of the Non-EQ Instrumentation Circuits Test Review Program that are disconnected during calibration. The current method for detecting deterioration of the insulation on instrumentation cables uses time-domain reflectometry (TDR). A proven cable test, such as TDR, will be conducted during the period of extended operation as part of the Non-EQ Instrumentation Circuits Test Review Program. The test frequency of instrumentation cables that are in the scope of this program, but are disconnected during calibration, shall be determined by I&M based on engineering evaluation, but will not be less than once per ten years. The test method selected by I&M is consistent with the proposed ISG-15 revision issued on August 12, 2003, NEI comments provided in the December 15, 2003, letter and the previously approved NRC Staff position documented in NUREG-1785, *License Renewal Safety Evaluation Report for the H. B. Robinson Steam Electric Plant, Unit 2* [Accession

No. ML040200981]. NUREG-1785, Section 3.6.2.3.2.2, discusses performing testing every 10 years for sensitive instrumentation circuits that are disconnected during calibration and are not part of the calibration program. The NRC Staff found testing acceptable because such testing would determine potential cable degradation, and the 10-year frequency was determined to be acceptable because cable insulation degradation is a slow process, plant-specific operating experience did not identify previous cable degradation, and this frequency is consistent with the NUREG-1801 cable aging management programs. A review of CNP operating experience found no age-related failures for the high-range radiation or the neutron monitoring cables. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01, which was not applicable to CNP, because the cable insulation material at CNP is different than that discussed in the bulletin. This plant operating experience demonstrates that these cables have operated over long periods without a loss of intended function. Therefore, the Non-EQ Instrumentation Circuits Test Review Program, which will include testing of instrumentation cables that are disconnected during calibration, will provide adequate management of the aging effects for instrumentation cables.

On the basis of the applicant's responses to RAI 3.6-2, the staff concludes that the applicant's commitment to use the Instrumentation Circuit Test Review Program, which will be consistent with the draft ISG-15, to manage the aging effects of electrical cables not subject to 10 CFR 50.49 requirements is acceptable. Therefore, the staff's concerns described in RAI 3.6-2 are resolved. This is Commitment # 38 in Appendix A of this SER .

Conclusion

The staff has verified the applicant's claim of consistency with the GALL Report. The staff has also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging for these components so that their intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application

In Section 3.6.2.2 of the LRA, the applicant provided further evaluation of aging management as recommended by the GALL Report for electrical and I&C components. The applicant provided information concerning how it will manage aging effects through the following two programs:

- Electrical Equipment Subject to Environmental Qualification Program
- Quality Assurance for Aging Management of Nonsafety related Components Program

Staff Evaluation

For component groups evaluated in the GALL Report for which the applicant 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 addresses the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.6.3.2 of the SRP-LR. The audit and review report contains details of this effort.

For some line items consistent with the GALL Report in LRA Table 3.6.2-1, the GALL Report recommends further evaluation. In cases where the GALL Report recommends further evaluation, the staff reviewed these additional evaluations provided in LRA Section 3.6.2.2 against the criteria provided in SRP-LR Section 3.6.2.2. Line items requiring no further evaluation are within the scope of the staff evaluation.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a TLAA as defined in 10 CFR 54.3. The TLAAs must be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviews the evaluation of this TLAA separately in Section 4.4 of this SER, following the guidance in Section 4.4 of the SRP-LR.

The staff reviewed Table 3.6.2-1 of the LRA, which summarizes the results of AMR evaluations in the SRP-LR for the electrical component groups. All items within the scope are consistent with the GALL Report.

Conclusion

On the basis of its review, the staff finds that the applicant's further evaluations conducted in accordance with the GALL Report are consistent with the acceptance criteria of the SRP-LR. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.2 Quality Assurance for Aging Management of Nonsafety related Components

The applicant implements site QA procedures, review and approval processes, and administrative controls in accordance with the requirements of Appendix B to 10 CFR Part 50. The CNP Quality Assurance Program applies to both safety related and nonsafety related SCs. Section 3.0.4 of this SER provides the staff evaluation of this program.

Conclusion

On the basis of its audit, the staff finds that the applicant's further evaluation conducted in accordance with the GALL Report is consistent with the acceptance criteria in Section 3.6.2.2 of the SRP-LR.

3.6.2.3 *AMR Results That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report*

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMRs for material, environment, AERM, and AMP combinations that are not consistent with or are not addressed in the GALL Report. The staff evaluation of the electrical and I&C component AMPs that are not consistent with or are not addressed in the GALL Report appears below.

3.6.2.3.1 High-Voltage Insulators

Summary of Technical Information in the Application

Table 2.5.1, "Electrical and Instrumentation and Control Systems Components Subject to Aging Management Review," of the LRA, identifies high-voltage insulators as a component within the scope of license renewal. Table 3.6.2-1, "Electrical Components, Summary of Aging Management Evaluation," of the LRA, does not list any aging effects associated with high-voltage insulators.

Staff Evaluation

The staff reviewed Section 4.5 of CNP LRP-EAMR-01, "Aging Management Review for Electrical Systems," which discusses aging effects for high-voltage insulators. The aging effects identified for high-voltage insulators requiring evaluation include the following:

- surface contamination
- cracking and loss of material

The report identifies various airborne materials such as dirt, salt, and industrial effluents that can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas, rain can wash away such contamination. The glazed insulator surface aids this contamination removal.

The loss of material or cracking due to mechanical wear is an aging effect for strain and suspension insulators if they are subject to significant movement. Movement of the insulators can result from wind blowing the supported transmission conductor, causing it to swing from side to side. Although this mechanism is possible, industry experience has shown that transmission conductors do not normally swing. When they do, because of a substantial wind, they do not continue to swing for very long once the wind has subsided. Wind that can cause insulators to vibrate is considered in the design and installation. Therefore, surface contamination and the loss of material due to wear of high-voltage insulators are not AERMs for the period of extended operation.

The staff agrees that the LRP-EAMR-01 report correctly identifies the aging effects and AMP associated with high-voltage insulators.

Conclusion

The staff agrees with the applicant's conclusion that high-voltage insulators do not require a separate AMP.

3.6.2.3.2 Switchyard Bus

Summary of Technical Information in the Application

Table 2.5.1 of the LRA identifies switchyard bus as a component within the scope of license renewal. Table 3.6.2-1 of the LRA does not list any aging effects associated with switchyard bus.

Staff Evaluation

The staff reviewed Section 4.5 of CNP LRP-EAMR-01 which discusses aging effects for switchyard bus. The aging effects identified for switchyard bus requiring evaluation include the following:

- surface oxidation
- vibration

The report identifies the most prevalent mechanism contributing to aging of an aluminum bus as connection surface oxidation, which can lead to increased resistance and heating. Oxidation of switchyard aluminum bus is a very slow-acting aging mechanism. Further, the report states that operating experience does not identify aging problems with the CNP switchyard bus. The Preventive Maintenance Program at CNP verifies that No-Ox grease is used on aluminum bus connections. The application of No-Ox grease precludes oxidation of the aluminum surface at the bus connections. The grease is checked routinely at CNP during bus maintenance. Therefore, the oxidation of the switchyard bus is not an aging mechanism that leads to a change in material properties resulting in increased resistance and heating. Therefore, oxidation of these components is not an AERM during the period of extended operation at CNP.
Wind can cause vibration of switchyard bus and insulators, but this is considered in the design and installation. Therefore, the aging effects of cracking that could be caused by bus vibration do not require management during the period of extended operation at CNP.

The staff agrees that the LRP-EAMR-01 report correctly identifies the aging effects and AMP associated with switchyard bus.

Conclusion

The staff agrees with the applicant that switchyard bus requires no separate AMP.

3.6.2.3.3 Fuse Holders

Summary of Technical Information in the Application

Section 2.1.3 of the LRA states that fuse holders are considered passive electrical components and are included in the AMR in the same manner as terminal blocks and other types of electrical connections. Consistent with ISG-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," the applicant considered fuse holders that are part of a larger assembly inside the enclosure of active components to be part of a larger assembly and not subject to an AMR. ISG-5 addresses fuse holders that are not part of a larger assembly, but that support safety related and nonsafety related functions in which a failure of a fuse precludes the performance of a safety function.

Staff Evaluation

RAI 3.6-1

In LRA Table 3.6.2-1, the staff did not find an AMR of results for fuse holders. In a letter dated May 5, 2004, the staff issued RAI 3.6-1 stating the following:

> In response to audit team's question on fuse holders, you stated that you have completed an assessment to identify fuse holders that are subject to AMR based on requirements of license renewal and ISG-5. The assessment identified fuse holders in scope for license renewal, then screened in fuse holders in-scope based upon whether (1) they are included in an active component (panels, switchgear, or cabinet), (2) they perform an intended function to meet the criteria of 10 CFR 54.4(a) (i.e., isolate safety loads from non-safety loads or are used as protective devices to ensure the integrity of containment electrical penetrations), or (3) they have bolted connections, which are not subject to the same aging stressors (i.e., mechanical stress and fatigue) as spring loaded fuse holder clips. The assessment determined that fuse blocks are either an active component, do not perform a license renewal intended function, or have bolted connections. With regard to the fuse holders that have bolted connections, please address the aging effects due to vibration, corrosion, and fatigue due to thermal cycling identified in the subject ISG and provide justification as to why an additional AMP for bolted connection fuse holders is not required.

By letter dated June 8, 2004, the applicant stated that the CNP AMR of electrical systems eliminates fuses with bolted connections, since bolted connections do not have the issue associated with metallic fuse clamps. Bolted connections on fuse holders are subject to the same aging effects as bolted connections included in the cables and connections commodity group. The CNP AMR includes bolted connections on fuse holders as connections in the cable and connections commodity group.

In a meeting on September 1, 2004, the staff contended that GALL AMP XI.E1 does not cover aging affects related to vibration, corrosion, and fatigue associated with fuse holders with bolted connections. The applicant stated that based on its review, no fuse holders at CNP are subject to the aging effects discussed in ISG-5.

The staff concluded that the applicant must confirm that no fuse holders at CNP are subject to the aging effects discussed in ISG-5. By letter dated October 18, 2004, the applicant confirmed that no fuse holders at CNP are subject to the aging effects discussed in ISG-5. On this basis, the staff concern described in RAI 3.6-1 above is resolved.

Conclusion

On the basis of its review and evaluation of the above RAI, the staff concludes that the applicant adequately identified that no fuse holders at CNP are subject to the aging effects discussed in ISG-5.

3.6.2.3.4 Station Blackout Components

Summary of Technical Information in the Application

The License Renewal Rule, Section 10 CFR 54.4(a)(3), requires that, "all systems, structures, and components 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." Under the station blackout (SBO) rule, therefore, offsite power systems provide a means of recovering from the SBO. This meets the criteria in 10 CFR 54.4(a)(3) as a system that performs a function that demonstrates compliance with the Commission's regulations on SBO. For this reason, 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.

In Section 2.5 of the LRA, the applicant described switchyard components that are relied on to support SBO recovery actions. The applicant identified the following components comprising the offsite power source path that are within the scope of license renewal:

- switchyard circuit breakers feeding the reserve auxiliary transformers
- reserve auxiliary transformers
- circuit breaker-to-transformer and transformer-to-onsite electrical distribution interconnections
- associated control circuits and structures

Staff Evaluation

RAI 2.5-1

In a letter dated May 6, 2004, the staff issued RAI 2.5-1, concerning the switchyard components that are relied on in safety analyses to perform a function in the recovery from SBO, as follows:

> ISG 2, "NRC Staff Position on the License Renewal Rule (10 CFR 54.4) as it Relates to the Station Blackout Rule (SBO) (10 CFR 50.63)," states, in part, that "The offsite power systems consist of a transmission system (grid) component that provides a source of power and a plant system component that connects that power source to a plant's onsite electrical distribution system which power safety equipment." For the purpose of the license renewal rule, the staff determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformer), transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. In this regard, the portion of the SBO path indicated on the offsite power boundary drawing for license renewal does not include the transmission conductors and connections and the associated control cables from the first breaker (disconnect) from the 345 kV [kilovolt] and 765 kV switchyard buses to the 765 kV/34.5 kV and 345 kV/34.5 kV transformers. Please revise this drawing to include the above components indicating which components require an aging management review (AMR).

In a letter dated June 8, 2004, the applicant stated that the portion of the SBO path indicated on license renewal offsite power boundary drawing 12-LRA-Electrical1 includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, and the intervening overhead or underground circuits between circuit breakers and transformers and between transformers and the onsite electrical distribution system. Switchyard items credited for the SBO path include the associated control circuits and structures, in addition to the items shown on the boundary drawing. Further, the path from the switchyard circuit breakers that connect to the offsite power system transformers (startup transformers) to the 765-kV/34.5-kV and 345-kV/34.5-kV switchyard transformers is considered part of the transmission system (grid), which is not included in the scope of license renewal and is not subject to an AMR. Therefore, the license renewal offsite power boundary drawing does not require any changes.

RAI 2.5-2

In addition, in a letter dated May 6, 2004, the staff issued RAI 2.5-2, concerning the transmission conductors that are relied on in safety analyses to perform a function in the recovery from SBO, as follows:

> Table 2.5-1 of the license renewal application (LRA) lists the electrical and instrumentation and control (I&C) components included in the AMR. This list does not include transmission conductors, and uninsulated ground conductors listed in the LRA Table 2.1.1. With regard to transmission conductor and connectors, it is stated that the transmission conductors have been screened out because they have no aging effect. Transmission conductors have been known to have loss of conductor strength. The most prevalent mechanism contributing to the loss of conductor strength is corrosion, which includes corrosion of steel core and aluminum strand pitting. Explain why no aging effects related to conductor corrosion have been identified that would cause a loss of function for the extended period of operation. Also, explain why no significant aging effects related to wind loading vibration or sway on high voltage connections has been identified. In addition, provide justification for excluding uninsulated ground conductors from the AMR.

In a letter dated June 8, 2004, the applicant stated that it screened out the transmission conductors not because they have no aging effects, but because they do not perform an intended function for CNP. The credited SBO recovery path for either unit at CNP has no transmission conductors. Connections of the startup transformers to the offsite power system are through switchyard bus and underground 34.5-kV insulated cables rather than transmission conductors. The 34.5-kV underground cables are medium-voltage insulated cables, not transmission conductors. Transmission conductors perform no license renewal intended function in other CNP applications. Therefore, this commodity type is not subject to an AMR.

With regard to the uninsulated ground conductors, the applicant stated that the uninsulated ground conductors do not perform an intended function, and are therefore not subject to an AMR.

On the basis of its review, including the applicant's responses to the RAIs, the staff concludes that the applicant adequately identified and provided an acceptable AMP to manage the aging effects associated with the components credited in the SBO restoration path.

Conclusion

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects for the components associated with the SBO restoration path and will have adequate AMPs for managing the aging effects for these components, such that the intended function of the components will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the electrical and I&C components that are within the scope of license renewal and subject to an AMR so that the intended functions will be consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 discussed the TLAAs in license renewal application (LRA) Sections 4.2 through 4.7.7. Sections 4.2 through 4.7 of this safety evaluation report (SER) document the staff's review of the TLAAs. The TLAAs are certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), the applicant for license renewal must provide 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 exemption, 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 and analyses for the Donald C. Cook Nuclear Plant (CNP) against the six criteria specified in 10 CFR 54.3 to identify TLAAs. The applicant indicated that it identified the calculations and analyses that meet the six criteria by searching the current licensing basis (CLB), including the updated final safety analysis report (UFSAR), design-basis documents, previous license renewal applications, technical specifications, and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued April 2001 (hereafter referred to as the SRP-LR). The applicant listed the following TLAAs in LRA Table 4.1-1, "List of CNP TLAAs":

- reactor vessel neutron embrittlement, including analyses for upper-shelf energy (USE), pressurized thermal shock (PTS), and pressure-temperature (P-T) limits
- metal fatigue, including American Society of Mechanical Engineers (ASME) Code Class 1 and non-Class 1, and environmentally-assisted fatigue
- environmental qualification of electrical components
- containment liner plate and penetration fatigue analyses
- concrete containment tendon pretress
- reactor coolant system (RCS) piping leak-before-break
- ASME Code Case–481 (reactor coolant pump casings)
- ice condenser lattice frame
- reactor vessel underclad cracking
- steam generator tubes–flow induced vibration
- fatigue of cranes

Pursuant to 10 CFR 54.21(c)(2), the applicant listed only one plant-specific exemption based on TLAA, which exempts CNP, Units 1 and 2, from implementing the requirements of Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50 and to instead utilizes ASME Code Case N-641, "Alternative Pressure-Temperature Relationship and Low Temperature Overpressure Protection System Requirements." The applicant stated that it projected the P-T limits evaluations for both units to 60 years, and therefore, continuation of the exemption is justified for the period of extended operation.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to CNP, Units 1 and 2, and discussed exemptions based on TLAAs. The staff reviewed the information to determine whether the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

10 CFR 54.3 defines TLAAs 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 10 CFR 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 10 CFR 54.4(b)

(6) are contained or incorporated by reference in the CLB

The applicant listed the TLAAs applicable to CNP in LRA Table 4.1-1, based on the applicant's review of the potential TLAAs listed in NUREG-1800, Table 4.1-2, "Potential Time-Limited Aging Analyses," and Table 4.1-3, "Additional Examples of Plant-Specific TLAAs as Identified in by the Initial License Renewal Applicants." Table 4.1-1 of the LRA did not include the following topics listed as applicable to pressurized water reactor (PWR) facilities:

(1) metal corrosion allowance

(2) inservice flaw growth analyses that demonstrate structure stability for 40 years

(3) inservice local metal containment corrosion analyses

(4) high energy line break analysis based on cumulative usage factor

(5) fatigue analysis for the reactor coolant pump (RCP) flywheel

(6) flow-induced vibration endurance limit, transient cycle count assumptions, and ductility reduction of fracture toughness for the reactor vessel internals (RVIs)

The applicant stated in LRA Section 4.1 that loss of material by corrosion of structural components related to items 1 and 3 is addressed as part of the AMR processes discussed in LRA Section 3, and a review of inservice inspection (ISI) records indicated no defects that required analytical evaluation of the component through the end of the operating license (item 2). Further, the applicant did not postulate HELBs based on fatigue usage (item 4) at CNP because the design of Class 1 and non-Class 1 piping meets American National Standards Institute (ANSI) B31.1, "Piping Code." The RCP flywheel fatigue analysis (item 5) assumed a 60-year period of plant operation, which makes the analyses applicable to the period of extended operation. Although item 6 did not meet all six criteria for TLAAs, the Reactor Vessel Internals Program, discussed in SER Section 3.0.3.1, addresses ductility reduction of fracture toughness for RVI.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21 (c)(1). As required by 10 CFR 54.21(c)(2), the staff has confirmed that one 10 CFR 50.12 exemption has been granted on the basis of a TLAA to CNP, Units 1 and 2, from the requirements of Appendix G to 10 CFR Part 50. The applicant will instead utilize ASME Code Case N-641.

4.2 Reactor Vessel Neutron Embrittlement

Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," of the *Code of Federal Regulations* (10 CFR Part 50) provides the following regulations governing reactor vessel integrity:

- Pursuant to 10 CFR 50.60, all light-water reactors must meet the fracture toughness and material surveillance program requirements for the reactor coolant boundary as set forth in Appendices G and H to 10 CFR Part 50.

- Pursuant to 10 CFR 50.61, fracture toughness requirements protect against pressurized thermal shock.

The applicant identified three analyses affected by irradiation embrittlement that were described as TLAAs. Section 4.2.1, "Charpy Upper-Shelf Energy," Section 4.2.2, "Pressurized Thermal Shock," and Section 4.2.3, "Pressure-Temperature Limits," of this SER discuss these analyses.

Neutron embrittlement is a potentially significant aging mechanism for all ferritic materials that have a neutron fluence of greater than 1×10^{17} n/cm^2 ($E \geq 1.0$ million electron volts (MeV)). The relevant calculations use predictions of the cumulative damage to the reactor pressure vessel (RPV) from neutron embrittlement and were originally based on a 40-year period of plant operation. The RPV contains the core fuel assemblies and is made of thick steel plates that are welded together. Neutrons from the fuel in the reactor irradiate the vessel during operation and change the material properties of the steel. The most pronounced and significant changes occur in the fracture toughness material property. Fracture toughness is a measure of the resistance to crack extension under stresses. Embrittlement is a reduction in this material property resulting from irradiation. The largest amount of embrittlement usually occurs at the section of the vessel's wall closest to the reactor fuel, referred to as the vessel's beltline. The embrittlement of the beltline material depends on its chemical composition, and copper and nickel are the most important chemical elements in determining how sensitive the steel is to neutron irradiation.

4.2.1 Charpy Upper-Shelf Energy

The U.S. Nuclear Regulatory Commission (NRC) provides screening criteria for the USE material property in 10 CFR Part 50, Appendix G. Appendix G requires that RPV beltline materials have Charpy USE values in the transverse direction for the base metal and along the weld for the weld material of no less than 102 joules (J) (75 foot-pounds (ft-lb)) initially, and maintain Charpy USE values throughout the life of the vessel of no less than 68 J (50 ft-lb). However, in accordance with paragraph IV.A.1.a. of Appendix G to 10 CFR Part 50, Charpy 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 Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Boiler and Pressure Vessel (B&PV) Code. Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," issued May 1988, provides an expanded discussion regarding the calculation of Charpy USE values and describes two methods for determining Charpy USE values for RPV beltline materials, depending on whether or not a given RPV beltline material is represented in the plant's Reactor Vessel Material Surveillance Program (*i.e.*, the 10 CFR Part 50, Appendix H program). If surveillance data are not available, the Charpy USE values are determined in accordance with Position 1.2 in RG 1.99, Revision 2. If two or more surveillance data are available, the Charpy USE values should be determined in accordance with Position 2.2 in RG 1.99, Revision 2. These methods refer to Figure 2 in RG 1.99, Revision 2, which indicates that the percentage drop in Charpy USE values is dependent upon the amounts of copper and the neutron fluence. Because the analyses performed in accordance with Appendix G to 10 CFR Part 50 are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4T), the Charpy USE analysis uses the neutron fluence at the 1/4T depth location.

4.2.1.1 Summary of Technical Information in the Application

Appendix G to 10 CFR 50 requires that, "Reactor vessel beltline materials must have Charpy upper-shelf energy...of no less than 75 ft-lb (102 J) initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb (68 J)...." The applicant originally documented its analyses of USE for 32 effective full-power years (EFPYs) in its response to NRC Generic Letter 92-01, Revision 1, "Reactor Vessel Structural Integrity." The number of EFPYs at the end of the period of initial operation (40 years) is assumed to be 32, using an assumed 80-percent capacity factor. Similarly, 48 EFPYs are assumed at the end of the period of extended operation (60 years), using an assumed 80-percent capacity factor.

RG 1.99, Revision 2, provides two methods (or positions) for determining Charpy USE. Following Position 1, the percent drop in Charpy USE for a stated copper content and neutron fluence is determined by reference to Figure 2 of RG 1.99. This percentage drop is applied to the initial Charpy USE to obtain the adjusted Charpy USE. For Position 2, the percent drop in Charpy USE is determined by plotting the available data on Figure 2 and fitting the data with a line drawn parallel to the existing lines that represent the upper bounds of all the plotted points.

Table A-2 of Westinghouse Commercial Atomic Power (WCAP)-15879, Revision 0, "Evaluation of Pressurized Thermal Shock for D.C. Cook Unit 1 for 40 Years and 60 Years," reports the 48 EFPY Charpy USE values for the reactor vessel beltline materials for Unit 1; Table A-2 of WCAP-13517, Revision 1, "Evaluation of Pressurized Thermal Shock for D.C. Cook Unit 2," reports the values for Unit 2. Using the methodology presented in Position 1, the applicant calculated the CNP USE values. The 48 EFPY fluence at one fourth of the way through the vessel wall (T/4) is based on a peak clad base metal fluence of 2.831×10^{19} n/cm^2 and 2.457×10^{19} n/cm^2 for Units 1 and 2, respectively. The fluence at the T/4 location for Units 1 and 2 was calculated in accordance with RG 1.99, Equation 3.

Fluence values at 48 EFPYs were obtained using the method described in Section 6 of WCAP-12483, Revision 1, "Analysis of Capsule U from the American Electric Power Company D.C. Cook Unit 1 Reactor Vessel Radiation Surveillance Program," for Unit 1 and WCAP-13515, Revision 1, "Analysis of Capsule U from Indiana Michigan Power Company D.C. Cook Unit 2, Reactor Vessel Radiation Surveillance Program," for Unit 2. The projected 48 EFPY exposure for Unit 1 includes the plant- and fuel cycle-specific calculated fluence at the end of cycle 16, a projection to the end of cycle 17, and future projections to 32 EFPYs and 48 EFPYs. The projection to cycle 17 was based on the cycle 17 design power distribution, continued operation at a core power level of 3250 megawatts-thermal (MWt), and a design cycle length of 1.45 EFPYs. Projection beyond cycle 17 was based on the assumption of low leakage fuel management and a representative power distribution burnup averaged over cycles 15 through 17. The analysis conservatively assumed that, for cycles 18 and beyond, the core power level would be uprated to 3600 MWt. In addition, the analysis applied a positive bias of 10 percent to the neutron source in all fuel assemblies located on the core periphery.

The projected 48 EFPY fluence exposure for Unit 2 includes the plant-specific and fuel cycle-specific calculated fluence at the end of cycle 11, a projection to the end of cycle 12, and projections to 32 EFPYs and 48 EFPYs. The projection to cycle 12 was based on the cycle 12 design power distribution, continued operation at a core power level of 3411 MWt, and a design cycle length of 1.4 EFPYs. Projections beyond cycle 12 were based on assumptions of low-leakage fuel management and that a representative power distribution burnup averaged over cycles 10 through 12 would be typical of future operating cycles. The analysis conservatively assumed that, for cycles 13 and beyond, the core power level would be uprated to 3800 MWt. In addition, the analysis applied a positive bias of 10 percent to the neutron source in all fuel assemblies located on the core periphery.

The NRC recently reviewed the fluence methodology in WCAP-12483 and WCAP-13515, Revision 1, and concluded that the methodology uses approximations, geometrical description, and cross sections in accordance with the guidance in RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," issued March 2001. In projecting the fluence values, Indiana Michigan Power Company (I&M) incorporated a power level that would bound anticipated future power uprates. The fluence calculation methods described in WCAP-12483 and WCAP-13515 are concordant.

As shown in Table 4.2-1 and Table 4.2-2 of the LRA, the Charpy USE is maintained above 68 J (50 ft-lb) for all base metal (plates and forgings) and welds at 48 EFPYs for both units. The applicant shows an end of extended operation limiting beltline material Charpy USE of 57 ft-lb for the intermediate/lower shell circumferential weld of Unit 1 and 66 ft-lb for the intermediate shell plate of Unit 2. According to regulations, an equivalent margins analysis is not required for either Unit 1 or Unit 2. Therefore, the applicant has evaluated USE in accordance with 10 CFR 54.21(c)(1)(ii) and projected the analyses to the end of the period of extended operation.

A comparison of copper content and initial unirradiated Charpy USE values for the Units 1 and 2 beltline materials listed in Tables 4.2-1 and 4.2-2 of the LRA to the values reported in the NRC reactor vessel integrity database (RVID2) indicates slight differences for selected plate and weld materials. These slight differences are not significant and do not alter the conclusion that Charpy USE is maintained above 68 J (50 ft-lb) for all base metal (plates and forgings) and welds at 48 EFPYs for both units. Table 4.2-1 of the LRA does not list the nozzle shell material for Unit 1 as it is not considered to be a limiting material in accordance with the beltline definition provided in 10 CFR 50.61(a)(3).

4.2.1.2 Staff Evaluation

The applicant summarized the Charpy USE analyses for the CNP RPV beltline materials in Tables 4.2-1 and 4.2-2 of the LRA. Since all reported end of extended operation Charpy USE values are above the 68 J (50 ft-lb) screening criterion, the staff finds that, with respect to Charpy USE, the CNP RPVs have sufficient margin to perform their intended function through the period of extended operation.

The applicant's end of extended license Charpy USE values are based on the fluence and material information in a series of WCAP reports submitted as attachments in support of the current P-T limits at 32 EFPYs, which the NRC approved in its safety evaluation (SE) dated July 18, 2003, for Unit 1 and the NRC SE dated March 20, 2003, for Unit 2. The WCAP reports for Unit 1 include WCAP-12483, Revision 1, for the fluence calculational methodology and results; WCAP-15878, Revision 0, "D.C. Cook Unit 1 Heatup and Cooldown Limit Curves for Normal Operation for 40 Years and 60 Years," for P-T limits; and WCAP-15879, Revision 0, for PTS calculations. The corresponding reports for Unit 2 include WCAP-13515, Revision 1; WCAP-15047, Revision 2, "D.C. Cook Unit 2 WOG Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation;" and WCAP-13517, Revision 1. Although these WCAP reports contain fluence and material property information for both 32 EFPYs and 48 EFPYs, the approved P-T limits for both units are for 32 EFPYs.

The staff confirmed that the Charpy USE-related information in the LRA is consistent with the WCAP reports and the relevant NRC SEs. The fluence calculational methodology, which used approximations, geometrical descriptions, and cross sections in accordance with RG 1.190, is acceptable to the staff, as stated in the two SEs referenced above. Because all of the end of extended license Charpy USE values are above the 68 J (50 ft-lb) screening criterion, the staff finds that, with respect to Charpy USE, the CNP RPVs have sufficient margin to perform the intended function through the period of extended operation.

RAI 4.2.1-1

For additional assurance, the staff performed an independent calculation of the end of extended license Charpy USE values for the limiting beltline plate and weld of the CNP reactor pressure vessels (RPVs) and confirmed that the applicant's end of extended license Charpy USE values for the limiting beltline plate and weld are above the 68 J (50 ft-lb) screening criterion and, except for the three welds of Unit 2, are in reasonable agreement with the staff's calculated values. For example, the end of extended operation limiting beltline material Charpy USE values calculated by the staff is 58 ft-lb for Unit 1 and 65 ft-lb for Unit 2 , close to the applicant's values of 57 and 66 ft-lb respectively. To clarify the discrepancy with the three welds of Unit 2, the staff issued RAI 4.2.1-1. By letter dated June 16, 2004, the applicant responded to the RAI by stating that it based all end of extended license USE values for Unit 1 beltline plates and welds and Unit 2 plates on RG 1.99, Revision 2, Position 1.2. Consequently, the applicant, in its letter dated August 11, 2004, indicated that it based the end of extended license USE values for Unit 2 beltline welds on RG 1.99, Revision

2, Position 2.2. The staff verified that, when the analysis uses surveillance data (Position 2.2), the staff's end of extended license USEs for the three welds of Unit 2 correspond to those in LRA Section 4.2.1. The staff also reviewed the Charpy USE values at 32 EFPYs for all beltline and nozzle materials, including nozzle shell plates and welds, which are not reported in the LRA, to ensure that the limiting plate and weld at 32 EFPYs remain limiting at the end of the extended license period. Since the applicant's RPV Material Surveillance Program includes some beltline materials (refer to Aging Management Program (AMP) B.1.26 in Section 3.0.3.2.10 of this SER for a description of the Reactor Vessel Integrity Program), the staff applied Position 2.2 in RG 1.99, Revision 2, in estimating the percentage drop in end of extended license Charpy USE for these beltline materials. The staff confirmed that, although the percentage drop in end of extended license Charpy USE is greater using Position 2.2 in the RG for the two beltline plates of Unit 1 having surveillance data, the change is not large enough to make either one limiting. Therefore, all RPV beltline shell and nozzle materials will continue to satisfy the Charpy USE value requirements of Appendix G to 10 CFR Part 50, through the period of extended operation for the CNP units. Thus, the staff concludes that the applicant's TLAA for calculating the end of extended license Charpy USE values of the CNP RPV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RPV materials will have adequate Charpy USE values and fracture toughness through the period of extended operation.

4.2.2 Pressurized Thermal Shock

Fracture toughness requirements to protect the RPVs of PWRs against possible consequences of PTS are founded in 10 CFR 50.61. Licensees must perform an assessment of the RPV materials' projected values of the reference temperature (RT) for PTS (RT_{PTS}) through the end of their operating licenses. The regulation requires each licensee to calculate the end-of-license RT_{PTS} value for each material located within the beltline of the RPV. The RT_{PTS} value for each beltline material is the sum of the unirradiated reference nil-ductility transition temperature (unirradiated RT_{NDT}), the shift in the RT_{NDT} value caused by neutron irradiation of the material (ΔRT_{NDT}), and a margin value to account for uncertainties (M). The regulation provides screening criteria against which the calculated values are evaluated.

Pursuant to 10 CFR 50.61 (b)(2), RPV beltline base metal materials (forging or plate materials) and longitudinal (axial) weld materials have adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 132 °C (270 °F). The RPV beltline circumferential weld materials are considered to have adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 148 °C (300 °F). In this RG, ΔRT_{NDT} is the product of a chemistry factor and a fluence factor, where the fluence factor is dependent on the neutron fluence at the clad-to-base metal interface, and the chemistry factor is dependent on information from either the surveillance material or from the tables in the RG. 10 CFR 50.61(c) provides two methods for determining RT_{PTS}, one for material that does not have surveillance data available and one for material that has surveillance data. RG 1.99, Revision 2, Sections 1.1 and 2.1, respectively describe the two methods. If the RPV beltline material is not represented by surveillance data, its chemistry factor may be determined using the tables and the methodology documented in Position 1.1 in the RG. A chemistry factor determined from the tables in the RG will vary according to the amount of copper and nickel in the material. If the RPV beltline material is represented by surveillance data, its chemistry factor may be determined from the surveillance data using the methodology documented in Position 2.1 of the RG. The methods of determining RT_{PTS} values in 10 CFR 50.61 are equivalent to the methods of determining RT_{NDT} values in RG 1.99, Revision 2.

4.2.2.1 Summary of Technical Information in the Application

Section 4.2.2 of the LRA addressed the requirement that RPV beltline materials have RT_{PTS} values not exceeding the screening criteria of 10 CFR 50.61 for the licensed period of operation of the vessel. The applicant stated that the RT_{PTS} values have been calculated for all beltline materials through the period of extended operation using Position 1.1 and Position 2.1 in RG 1.99, Revision 2, as reported in LRA Section 4.2.2. A value of 48 EFPY was used as the end of extended license criterion for the RPVs. Table 4.2-3, "Evaluation of Reactor Vessel (48 EFPY) PTS - Unit 1," and Table 4.2-4, "Evaluation of Reactor Vessel (48 EFPY) PTS - Unit 2," of the LRA contain RT_{PTS} information for all beltline materials. This information includes the weight percent of copper and nickel in the steel, the end of extended operation fluence for the RPV clad-to-base metal interface, the initial RT_{NDT}, and the calculated RT_{PTS} values at the end of the extended operation. Specifically, the end of extended operation limiting beltline material RT_{PTS} is reported to be 139 °C (283 °F) for the intermediate/lower shell circumferential weld of Unit 1 and 108 °C (227 °F) for the intermediate shell plate of Unit 2. The applicant concluded that the end of extended license RT_{PTS} results are below the screening criteria of 132 °C (270 °F) for plates and axial welds and 148 °C (300 °F) for circumferential welds. The applicant stated that it has projected the calculations through the period of extended operation and has met the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.2.2 Staff Evaluation

The applicant summarized the end of extended operation RT_{PTS} results for the CNP RPV beltline materials in Tables 4.2-3 and 4.2-4 of the LRA. Because the end of extended operation RT_{PTS} values are below the screening criteria of 10 CFR 50.61, the staff finds that, with respect to RT_{PTS}, the applicant's RPVs have sufficient margin to perform their intended function through the period of extended operation.

The applicant based end of extended operation RT_{PTS} values on the fluence and material information found in the same series of WCAP reports submitted as attachments to support the current P-T limits at 32 EFPYs for Unit 1 and the P-T limits at 32 EFPYs for Unit 2 which are discussed in Section 4.2.1.2 of this SER. The staff confirmed that the RT_{PTS}-related information in the LRA, including the fluence calculational methodology and results, is consistent with that in the WCAP reports and in the NRC SEs referenced in Section 4.2.1.2 of this SER. The staff performed an independent calculation of the end of extended operation RT_{PTS} values for the limiting beltline plate and weld of the CNP RPVs and confirmed that the applicant's end of extended operation RT_{PTS} values and the staff's calculated values for the limiting beltline plate and weld are identical and below the screening criteria. The staff also reviewed the RT_{PTS} values at 32 EFPYs for all beltline and nozzle materials, including nozzle shell plates and welds, which are not reported in the LRA, to ensure that the limiting plate and weld at 32 EFPYs remain limited at the end of extended license. For the beltline materials having surveillance data, the staff applied Position 2.2 in RG 1.99, Revision 2, as well as Position 1.2, in estimating its end of extended license RT_{PTS} values and confirmed that the surveillance data predicted less embrittlement. Based on the above discussion, the staff concludes that all RPV beltline shell and nozzle materials will continue to satisfy the RT_{PTS} value requirements of 10 CFR 50.61 through the period of extended operation for the CNP units. The applicant's TLAA for calculating the end of extended license RT_{PTS} values of the CNP RPV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RPV materials will have adequate RT_{PTS} values and fracture toughness through the period of extended operation for the CNP units.

4.2.3 Pressure-Temperature Limits

The NRC designed the requirements in Appendix G to 10 CFR Part 50 to protect the integrity of the reactor coolant pressure boundary (RCPB) in nuclear power plants. The applicant established the P-T limits by calculations that use 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 of the current operating license.

The staff evaluates the P-T limit curves based on NRC regulations and guidance. Appendix G to 10 CFR Part 50 requires that P-T limit curves be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Code. Appendix G to 10 CFR Part 50 also provides minimum temperature requirements that an applicant must consider in the development of the P-T limit curves. Section 5.3.2 of the SRP-LR provides an acceptable method for determining the P-T limit curves for ferritic materials in the beltline of the RV based on the linear elastic fracture mechanics methodology of Appendix G to Section XI of the ASME Code. The critical locations in the RV beltline region for calculating heatup and cooldown P-T curves are the 1/4T and 3/4T locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.

4.2.3.1 Summary of Technical Information in the Application

Appendix G to 10 CFR Part 50 requires operation of the RPV within established P-T limits. Analyses based on data obtained through the unit-specific Reactor Surveillance Capsule Program establish these limits.

I&M submitted license amendment requests for the Unit 1 and 2 RCS P-T curves. The revised Unit 1 P-T curves, which the NRC approved by means of License Amendment Number 278, specify limits on RCS pressure and temperature for up to 32 EFPYs. For cycle 18 and beyond, the curves are based on an assumed core power level of 3600 MWt. The revised Unit 2 P-T curves, which the NRC approved by means of License Amendment Number 255, specify limits on RCS pressure and temperature for up to 32 EFPYs, based on an assumed core power level of 3800 MWt. The revised P-T curves are based on fluence analysis that complies with RG 1.190 and uses ASME Code Case N-641. The bases for the Units 1 and 2 EFPY P-T limits are documented in WCAP-15878, Revision 0, and WCAP-15047, Revision 2, respectively. In addition, Section 9.0, Figures 9-3 and 9-4, of each respective WCAP, report the 48-EFPY P-T results. The operating window at 48 EFPYs is sufficient to conduct normal heatup and cooldown operations for both Units 1 and 2. Therefore, the applicant has projected approved P-T limits for Units 1 and 2 to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.3.2 Staff Evaluation

Similar to the end of extended license Charpy USE and RT_{PTS} values discussed in Sections 4.2.1.2 and 4.2.2.2 of this SER, the applicant based its end of extended license P-T limits on the fluence and material information in the WCAP reports submitted as attachments to support the current P-T limits at 32 EFPYs for Units 1 and 2. The staff confirmed that the information related to P-T limits in the LRA, including the fluence calculational methodology and results, is consistent with that in the WCAP reports and in the NRC SEs approving the current P-T limits for CNP units. Thus, the applicant's TLAA for calculating the end of extended license P-T limits of the CNP RPV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the operating window at 48 EFPYs is sufficient to conduct normal heatup and cooldown operations through the period of extended operation for the CNP units. However, accepting the applicant's TLAA regarding P-T limits for 48 EFPYs does not mean that the CNP licensing basis may now include these limits. The NRC will process any P-T limit change for CNP, Units 1 and 2, as separate license amendments; which could modify the facility's technical specifications.

4.2.4 UFSAR Supplement

On the basis of the staff's evaluation described above, the summary description for the RCS TLAA for RPV Charpy USE, PTS, and P-T limits described in the UFSAR Supplement (Appendix A to the LRA) adequately describes this TLAA, as required by 10 CFR 54.21.

4.2.5 Conclusion

The staff reviewed TLAAs regarding the maintenance of acceptable Charpy USE values and P-T limits for the CNP RPV materials and the ability of the CNP RPV to resist failure during postulated PTS events. Based on this evaluation, the staff concludes that the applicant's TLAAs for Charpy USE, PTS, and P-T limits meet the respective requirements of Appendix G to 10 CFR Part 50, as well as 10 CFR 50.61 for the CNP RPV beltline materials to the end of extended license. Therefore, they satisfy the requirements of 10 CFR 54.21(c)(1)(ii) to the end of the period of extended operation. However, the NRC must process any P-T limit changes for CNP, Units 1 and 2, as separate license amendments, thereby, modifying the facility's technical specifications.

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 design of CNP RCPB components in Section 4.3.1 of the LRA. The pressurizer, reactor vessel, control rod drive mechanism (CRDM) housings and steam generators were designed to the ASME Boiler and Pressure Vessel Code, Section III requirements for Class 1 components. The reactor vessel internals were evaluated using the ASME Code Class 1 fatigue criteria. Table 4.3-1 of the LRA lists the transients and number of transient cycles used in the design of ASME Class 1 components. Table 4.3-1 also lists the estimated number of transient cycles for 60 years of plant operation for each unit. The applicant estimated that the number of design cycles will remain bounding for the period of extended operation. Therefore, the applicant indicated that the fatigue analyses will remain valid in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

The applicant indicated that the Fatigue Monitoring Program (FMP) tracks the RCS design transients. The FMP is described in Appendix B of the LRA.

The applicant indicated that RCPB (Class 1) piping was designed to United States of America Standard (USAS) B31.1. This standard does not require an explicit fatigue analysis of piping components. However, USAS B31.1 does require a reduction in the allowable bending stress range if the number of full range bending stress cycles exceed 7,000. The applicant indicated that, based on its review of the Class 1 piping systems, the existing analyses remain valid for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

In addition to the design of ASME Code Class 1 components using transient cycles listed in Table 4.3-1 of the LRA, the applicant identified evaluations performed to address other specific issues. These evaluations were performed for the surge line to address NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification," and the normal and alternate charging lines and the auxiliary pressurizer spray line to address NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The applicant indicated that the fatigue analyses of these lines remain valid for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

The applicant discussed the evaluation of non-Class 1 components in Section 4.3.2 of the LRA. The applicant indicated that the equipment specifications for several heat exchangers required that the supplier verify that ASME Code Section III, paragraph N-415.1 was satisfied for the design transients. As discussed above, the applicant estimated that the number of design cycles will remain bounding for the period of extended operation. Therefore, the fatigue analyses remain valid in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

The applicant indicated that non-Class 1 piping was designed to USAS B31.1. Therefore, the piping components require that a stress reduction factor be applied to the allowable thermal bending stress range if the number of full range cycles exceeds 7,000. The applicant indicated that most piping systems within the scope of license renewal are bounded by the 7,000 cycles. Therefore, the applicant concluded that the existing pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant discussed the evaluation of environmentally assisted fatigue of RCPB components in Section 4.3.3 of the LRA. The applicant provided the results of an evaluation of the environmental effects on the components listed in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The applicant indicated that it used the environmental fatigue correlations in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," in the evaluations. The applicant's evaluation indicated that the environmental fatigue usage factor for the surge line may exceed 1.0 during the period of extended operation. The applicant committed to further actions to address the surge line prior to the period of extended operation.

4.3.2 Staff Evaluation

As discussed in the previous section, components of the CNP RCPB were designed to the Class 1 requirements of the ASME Code. These requirements contain explicit criteria for the fatigue analysis of components. Consequently, the applicant identified the fatigue analysis of these components as TLAAs. The staff reviewed the applicant's evaluation of the RCPB components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for fatigue analysis of RCPB components involves calculating the cumulative usage factor (CUF). The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion requires that the CUF not exceed 1.0. The applicant projected that the number of design cycles assumed for each transient will not be exceeded during the period of extended operation. Table 4.3-1 of the LRA provides the current cycle counts and estimated cycle counts at 60 years of plant operation for transients used in the design of ASME Code Class 1 components. The transients listed in Table 4.3-1 of the LRA include the design transients specified in UFSAR Table 4.1-10, except for the primary to secondary leak tests specified for the Unit 1 Model 51R replacement steam generators. The applicant indicated that it no longer performed this leak test and, therefore, did not listed it in Table 4.3-1.

Table 4.3-1 indicated that unit loading and unloading transients at 5 percent of full power per minute are not monitored. The applicant indicated that the number of these design transients is conservative because CNP units are base loaded plants. The staff agrees that the number of design cycles listed for these transients is conservative based on the information presented in NUREG/CR-6260 on older vintage Westinghouse plants. The applicant also indicated that secondary side hot standby feedwater cycling is not monitored due to modified plant design and operating procedures to preclude feedwater nozzle cracking. These modifications were described in a November 26, 1979, I&M letter to the NRC. The remaining transients are tracked by the applicant's FMP. The staff finds that the applicant's FMP tracks the significant design transients listed in Table 4.3-1.

The Westinghouse Owners Group (WOG) issued Topical Report WCAP-14577, Revision 1-A, "Aging Management for Reactor Internals," to address the aging management of the RVI. Section 2.3.1 of the LRA indicates that WCAP-14577, Revision 1-A was reviewed as a source of input information for CNP. The staff's review of WCAP-14577, Revision 1-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 11 specified in WCAP-14577, Revision 1-A indicates that the fatigue TLAA of the RVI should be addressed on a plant specific basis. Section 4.3 of the LRA indicates that the action item was addressed in Section 4.3.1 of the LRA. In Section 4.3.1, the applicant indicated that the number of design transients will not be exceeded during the period of extended operation. Additionally, the applicant's FMP will track the number of design transient cycles during the period of extended operation. The staff finds that the applicant has adequately addressed Renewal Applicant Action Item 11 specified in WCAP-1577, Revision 1-A by assuring that the design transients that are significant contributors to design fatigue usage of the RVI components will be monitored by the FMP.

The WOG issued WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," to address aging management of the RCS piping. Section 2.3.1 of the LRA indicates that WCAP-14575-A, 1-A was reviewed as a source of input information for CNP. Tables 3-2 through 3-16 of WCAP-14575-A list RCS components for which fatigue could be significant. The staff review of WCAP-14575-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 8 indicates that the applicant should address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575-A. As discussed previously, the design of RCPB piping conforms to the requirements of USAS B31.1. The standard does not require an explicit fatigue analysis. Instead, USAS B31.1 requires that a stress reduction factor be applied to the allowable thermal bending stress range if the number of full range cycles exceeds 7,000. The applicant indicated that the number of full range bending stress cycles will not exceed 7,000 during the period of extended operation for the RCPB piping. The staff finds that the applicant's actions adequately address Renewal Applicant Action Item 8. The applicant did perform fatigue analyses of some RCPB piping in response to NRC Bulletins 88-08 and 88-11.

The WOG has issued the generic WCAP-14574-A to address aging management of pressurizers. Section 2.3.1 of the LRA indicates that WCAP-14574-A was reviewed as a source of input information for CNP. The staff's review of WCAP-14574-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 1 requests the applicant to demonstrate that the pressurizer sub-component CUFs remain below 1.0 for the period of extended operation. Table 2-10 of WCAP-14574-A indicates that the ASME Code, Section III, Class 1 fatigue CUF criterion could be exceeded at several pressurizer sub-component locations during the period of extended operation. WCAP-14574-A also identifies recent unanticipated transients not considered in the original ASME Code, Section III, Class 1 fatigue analyses, including inflow/outflow thermal transients.

The applicant indicated that it had modified CNP operating procedures to decrease the severity of transients resulting from pressurizer surges during heatup and cooldown. The applicant stated that its reevaluation of the usage factors of the limiting pressurizer items in the lower head had shown them to be less than 1.0. The applicant also indicated that the evaluation was updated for 60 years and the usage factors still remain below 1.0. The staff finds that the applicant's reevaluation has adequately addressed the renewal applicant action item related to its concern about the pressurizer sub-component fatigue usage for the period of extended operation, including inflow/outflow thermal transients.

Renewal Applicant Action Item 1 also requested that the applicant discuss the impact of the environmental fatigue correlations provided in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/ CR-5704 on the above results. The applicant did not discuss this issue in the LRA. The applicant has not provided the CUFs for the sub-components listed in Table 2-10 of WCAP-14574-A or discussed the impact of the environmental fatigue correlations on these sub-components. As discussed previously, the applicant's evaluation of the surge line indicated that the environmental fatigue usage factor may exceed 1.0 during the period of extended operation. The staff concludes that a possibility exists that the components listed in Table 2-10 of WCAP-14574-A could also exceed the fatigue usage limit during the period of extended operation when environmental fatigue effects are considered.

The staff review of previous license renewal applications for Westinghouse facilities found that the pressurizer surge line nozzle is the most limiting fatigue location for the pressurizer sub-components. The staff concludes that the pressurizer surge line nozzle is an acceptable sample component location for assessing the impact of environmental fatigue on the CNP pressurizer components. The applicant committed to conduct further actions to address environmental fatigue of the surge line piping prior to the period of extended operation. This part of Commitment #31 in Appendix A of this SER. If the applicant's evaluation of the surge line nozzle for environmental effects indicates that additional actions are required to manage its fatigue usage during the period of extended operation, then the applicant should evaluate the remaining pressurizer components for the effects of environmental fatigue as part of its corrective action.

RAI 4.3.1-1

The applicant discussed the fatigue evaluation of the Unit 1 auxiliary spray line that was performed in response to NRC Bulletin 88-08. The applicant indicated that this fatigue evaluation is contained in WCAP-14070, "Evaluation of Donald C. Cook Units 1 and 2 Auxiliary Spray Piping per NRC Bulletin 88-08," dated July 1994. The applicant stated that the basis of the transient definitions used in the analysis is the number of design heatup and cooldown transients and that the number of design transients was found acceptable for 60 years of plant operation. Therefore, the applicant concluded that the fatigue analysis results presented in WCAP-14070 remain valid for the period of extended operation. In RAI 4.3.1-1, the staff requested that the applicant provide a copy of WCAP-14070.

The applicant's June 16, 2004, response provided proprietary and non-proprietary versions of WCAP-14070. The staff's review of WCAP-14070 confirmed the applicant's statement that the transient definitions are based on the number of design heatup and cooldown cycles. The staff review also found that some of the cyclic loading conditions for the leaking auxiliary spray isolation valve appear to be time dependent. Therefore, the staff could not confirm the applicant's conclusion that the analysis remains valid for the period of extended operation. The applicant's October 18, 2004, response confirmed that some of the cycles assumed in the fatigue analysis are valid for only 40 years of plant operation. The applicant committed to perform one or more of the following four actions for the auxiliary spray line piping evaluated in WCAP-14070:

(1) perform a plant specific fatigue analysis of the auxiliary spray line piping prior to the period of extended operation to ensure that the CUFs remain less than 1.0

(2) repair the piping at the affected locations

(3) replace the piping at the affected locations

(4) manage the effects of fatigue of the auxiliary spray line piping by an NRC-approved inspection program at inspection intervals to be determined by a method acceptable to the NRC staff.

This is Commitment #40 in Appendix A of this SER. The staff notes that, if the fourth option is selected, the applicant must provide inspection details, including scope, qualification, method, and frequency to the NRC for review and approval prior to the period of extended operation. An AMP under the fourth option would be a departure from the design basis CUF evaluation, described in the UFSAR Supplements and, therefore, would require a license amendment pursuant to 10 CFR 50.59. In view of the above, the staff finds the applicant's proposed actions to be an acceptable approach to address fatigue of the auxiliary spray line piping during the period of extended operation in accordance with 10 CFR 54.21(c)(1).

RAI 4.3.2-1

The applicant discussed the evaluation of non-Class 1 components in Section 4.3.2 of the LRA. As discussed previously, USAS B31.1 requires a reduction in the allowable bending stress range if the number of full range bending stress cycles exceed 7,000. The applicant indicated that only the RCS sampling system piping could exceed 7,000 thermal cycles during the period of extended operation. The applicant further indicated that it had prepared a calculation to justify operation of the RCS sampling system piping for 99,000 cycles. The applicant then concluded that the RCS sampling system piping analysis is not a TLAA. In RAI 4.3.2-1, the staff requested that the applicant clarify whether it had prepared the RCS sampling system piping calculation to support the CNP LRA. The staff indicated that, if the applicant had prepared this calculation to support the LRA, then the sampling system piping analysis should be considered a TLAA that has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

The applicant's June 16, 2004, response indicated that the sampling piping calculation had been revised in response to a condition report that indicated that the 7,000 cycle could be exceeded during the current 40-year license term. The applicant reasoned that it had used a conservative number of cycles in the revised analysis and, therefore, the calculation was not based on an explicit time limit defined by the current operating term. The staff agrees that the number of cycles used by the applicant in the revised analysis is conservative for the period of extended operation. However, the staff still considers the applicant's pipe stress analysis a TLAA that was demonstrated to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant indicated that the FMP will continue during the period of extended operation and will assure that design cycle limits are not exceeded. The applicant's FMP tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components remain within their design basis. Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999, by concluding the following:

> 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.

RAI 4.3.3-1

Section 4.3.3 of the LRA discussed the applicant's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion referenced the fatigue sensitive component locations for an early vintage Westinghouse plant identified in NUREG/CR-6260. The applicant indicated that it had used the design usage factors provided in Table 5-98 of NUREG/CR-6260 for the evaluation of the charging nozzle, safety injection nozzle and RHR tee. The design usage factors reported in NUREG/CR-6260 were based on an evaluation of the Turkey Point facility, including a plant specific evaluation of the RHR piping and detailed finite element analyses of the charging and safety injection nozzles. In RAI 4.3.3-1, the staff requested that the applicant discuss the applicability of these analyses to the CNP. The staff requested that the discussion also compare piping sizes and thicknesses, including the design of the thermal sleeves between CNP and Turkey Point. The staff further requested that the discussion also include a comparison of the number and type of design transients cycles between CNP and Turkey Point.

The applicant's June 16, 2004 response indicated that the Class 1 RHR piping at the four-loop CNP units has a different configuration than the RHR piping at the three-loop Turkey Point units. Therefore, the applicant committed to undertake one or more of the following five actions for the RHR piping prior to the period of extended operation:

(1) perform a plant specific fatigue analysis, including environmental effects, to demonstrate that the CUF remain less than 1.0

(2) repair the Class 1 portions of RHR at the affected locations

(3) replace the Class 1 portions of RHR at the affected locations

(4) manage the effects of fatigue of the Class 1 portions of RHR piping by an NRC-approved inspection program at inspection intervals to be determined by a method acceptable to the NRC staff

(5) monitor ASME Code activities to use the environmental fatigue methodology approved by the ASME Code committee and the NRC

This is Commitment #35 in Appendix A of this SER. The fifth option is not an alternative option to resolve the environmental fatigue issue. The first and fourth options include the use of an environmental fatigue methodology approved by the NRC. The staff notes that, if the fourth option is selected, the applicant must provide the inspection details, including scope, qualification, method, and frequency to the to the NRC for review and approval prior to the period of extended operation. An AMP under the fourth option would be a departure from the design basis CUF evaluation, described in the UFSAR Supplements and, therefore, would likely require a license amendment pursuant to 10 CFR 50.59. On the basis of the above discussion, the staff finds the applicant's proposed program to be an acceptable plant-specific approach to address environmentally assisted fatigue of the RHR line during the period of extended operation in accordance with 10 CFR 54.21(c)(1).

The applicant's June 16, 2004, response indicated that the CNP charging and safety injection nozzles are similar to the ones evaluated in NUREG/CR-6260. The applicant referenced the RCS nozzle configurations shown in Figures 2-11 and 2-12 of WCAP-14575-A to support this position. The staff review of WCAP-14575-A found that the CNP nozzles are identified as second generation nozzle designs. Figures 2-11 and 2-12 show that these nozzles have a counterbore near the thermal sleeve attachment weld. The NUREG/CR-6260 finite element models of charging and safety injection nozzles do not show this counterbore. Therefore, the CNP nozzles are slightly different from the ones evaluated in NUREG/CR-6260. In addition, the applicant indicated that two of the safety injection nozzles do not contain thermal sleeves. The finite element models in NUREG/CR-6260 contain thermal sleeves. Therefore, the staff concludes that the NUREG/CR-6260 finite element models are not directly applicable to the CNP nozzles.

The applicant's response also indicated that the major design transients for CNP are similar to those evaluated in NUREG/CR-6260. The Turkey Point plant evaluated in NUREG/CR-6260 is a three-loop Westinghouse plant, while CNP is a four-loop Westinghouse plant. NUREG/CR-6260 also evaluates a four-loop Westinghouse plant. Section 5.4.5 of NUREG/CR-6260 indicates that the highest safety injection nozzle fatigue usage for the four loop Westinghouse plant occurred at the boron injection tank nozzle which is different from the location evaluated for Turkey Point.

On the basis of the above discussion, it was not clear to the staff whether the design usage factors for the charging and safety injection nozzles contained in Table 5-98 of NUREG/CR-6260 are directly applicable to CNP. The staff requested that the applicant provide additional information regarding this issue. In its September 21, 2004, supplemental response, the applicant committed to perform one or more of the following five actions for the safety injection and charging nozzles prior to the period of extended operation:

(1) perform a plant specific fatigue analysis, including environmental effects, to demonstrate that the CUF remain less than 1.0

(2) repair the Class 1 charging and safety injection nozzles at the affected locations

(3) replace the Class 1 charging and safety injection nozzles at the affected locations

(4) manage the effects of fatigue of the Class 1 charging and safety injection nozzles by an NRC-approved inspection program at inspection intervals to be determined by a method acceptable to the NRC staff

(5) monitor ASME Code activities to use the environmental fatigue methodology approved by the ASME Code committee and the NRC

This is Commitment #33 in Appendix A of this SER. The applicant's proposed actions are the same as those proposed above for the RHR piping and found acceptable by the staff. As discussed previously, if the fourth option is selected, the applicant must provide the inspection details, including scope, qualification, method, and frequency the to the NRC for review and approval prior to the period of extended operation. An AMP under the fourth option would be a departure from the design basis CUF evaluation described in the UFSAR Supplements and, therefore, would require a license amendment pursuant to 10 CFR 50.59. On the basis of the above discussion, the staff finds the applicant's proposed program to be an acceptable plant-specific approach to address environmentally assisted fatigue of the safety injection and charging nozzles during the period of extended operation in accordance with 10 CFR 54.21(c)(1).

4.3.3 UFSAR Supplement

The applicant provided a UFSAR Supplement description of the FMP in Section A.2.1.12 of the LRA and a description of its TLAA evaluation for Class 1 and non-Class 1 component fatigue analyses in Section A.2.2.2 of the LRA. The staff requested that the applicant update Section A.2.2.2 to include the following: (1) a discussion of each of the actions selected to evaluate the auxiliary spray line piping (Commitment #40) and (2) a discussion of each of the actions selected to evaluate the environmental fatigue of the safety injection nozzles, charging nozzles (Commitment #33) and the RHR line (Commitment #35). The staff identified this as Confirmatory Item 4.3-1.

The applicant's January 21, 2005, response provided the updated UFSAR Supplement for Section A.2.2.2. The updated UFSAR Supplement contains a discussion of the applicant's commitment to perform additional actions to address fatigue of the auxiliary spray line piping prior to the period of extended operation and its commitment to perform additional actions to address environmental fatigue of the pressurizer surge line (Commitment #31), safety injection nozzles, charging nozzles and the RHR line prior to the period of extended operation. As described in the previous section of this SER, the staff considered these additional proposed actions and found them acceptable. The staff concludes that the revised UFSAR Supplement adequately describes the applicant's actions to address metal fatigue. Therefore, Confirmatory Item 4.3-1 is closed.

4.3.4 Conclusion

The staff has reviewed the applicant's metal fatigue TLAA and concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and finds that the applicant's revised UFSAR Supplement provides a sufficient description of the metal fatigue TLAA to satisfy the requirements of 10 CFR 54.21(d).

4.4 Environmental Qualification of Electrical Components

The TLAA for environmental qualification (EQ) of electrical components includes all long-lived, passive and active, electrical, and instrumentation and controls (I&C) components that are located in harsh environments. The harsh environments are those areas of the plant that are subjected to the environmental effects by a loss-of-coolant accident (LOCA) or HELB and that are important to safety. These components comprise safety related and Q-list equipment, nonsafety related equipment, the failure of which could prevent satisfactory accomplishment of any safety related function, and the necessary post-accident monitoring equipment.

Pursuant to 10 CFR 54.21(c)(1), applicants must provide a list of EQ TLAAs in the LRA and must demonstrate one of the following three items for each EQ component:

(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

(3) The effect of aging on the intended functions will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

The CNP Environmental Qualification of Electrical Components Program (hereafter referred to as the Environmental Qualification (EQ) Program) manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Pursuant to 10 CFR 50.49(f), EQ components not qualified for the applicable term must be refurbished, replaced, or have their qualification extended before reaching the qualified aging limits. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAAs for license renewal. The EQ Program ensures the maintenance of these EQ components within the bounds of their qualification.

The EQ Program is an existing CNP program that was established to meet commitments associated with10 CFR 50.49. The CNP EQ Program is consistent with Generic Aging Lessons Learned (GALL) Report, NUREG-1801, AMP X.E1,"Environmental Qualification of Electric Components."

Pursuant to 10 CFR 54.21(c)(1) the applicant chose option (3) to demonstrate that the EQ Program activities will adequately manage the effects of aging on the EQ equipment for the period of extended operation.

4.4.2 Staff Evaluation

For the electrical equipment identified in LRA Section 4.4, the applicant used the criteria of 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that it will adequately manage the aging effects of EQ equipment during the period of extended operation. The staff reviewed the EQ Program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended functions consistent with the CLB for the period of extended operation. The staff's evaluation of the components qualification focused on how the EQ Program manages the aging effects to meet the requirements delineated in 10 CFR 50.49.

The staff reviewed the information provided in the LRA. On the basis of its review, the staff finds that the EQ Program, which the applicant claimed to be consistent with GALL AMP X.E1, is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ Program provides reasonable assurance that the aging effects will be managed and that components within the scope of the EQ program will continue to perform their intended functions for the period of extended operation.

4.4.3 Conclusion

On the basis of this review, the staff concludes that the applicant has demonstrated that it will adequately manage the effects of aging on the intended functions of electrical components for the period of extended operation by using the existing EQ Program as required by 10 CFR 54.21(c)(1)(iii). The staff also concluded that the UFSAR Supplement contains a summary description of the programs and activities for the evaluation of TLAA as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress

4.5.1 Summary of Technical Information in the Application

The prestressing tendons in prestressed concrete containments lose prestressing forces with time as the result of creep and shrinkage of concrete, as well as relaxation of the prestressing steel. During the design phase, engineers estimate these losses to arrive at the predicted prestressing forces at the end of operating life, normally 40 years. The loss of tendon prestress analysis is a TLAA only for prestressed concrete containments.

This topic does not apply to ice condenser containments. The reinforced concrete containments at CNP do not use prestressed tendons.

4.6 Containment Liner Plate and Penetration Fatigue Analyses

The interior surface of a concrete containment structure is lined with thin metallic plates to provide a leak-tight barrier against the uncontrolled release of radioactivity to the environment, as required by 10 CFR Part 50. The thickness of the liner plates is generally between 6.2 mm (1/4 in.) and 9.5 mm (3/8 in.). The liner plates are attached to the concrete containment wall by stud anchors or structural rolled shapes, or both. The design process assumes that the liner plates do not carry loads. However, the anchorage system transfers normal loads, such as those from concrete shrinkage, creep, and thermal changes, imposed on the concrete containment structure to the liner plates. Internal pressure and temperature loads are directly applied to the liner plates. Thus, under design-basis conditions, the liner plates could experience significant strains.

The design may consider fatigue of the liner plates based on an assumed number of loading cycles for the current operating term. The cyclic loads include containment building interior temperature variation during the heatup and cooldown of the RCS, a LOCA, annual outdoor temperature variations, thermal loads because of high-energy containment, penetration piping lines (*e.g.* steam and feedwater lines), seismic loads, and pressurization from periodic Type-A integrated leak rate tests.

The containment liner plates, penetration sleeves (including dissimilar metal welds), and penetration bellows may be designed in accordance with the requirements of ASME B&PV Code, Section III. If a plant's code of record requires a fatigue analysis, then this analysis may be a TLAA and must be evaluated in accordance with 10 CFR 54.21(c)(1) to ensure that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.6.1 Summary of Technical Information in the Application

The applicant discussed the evaluation of the containment liner in Section 4.6.1 of the LRA. The applicant indicated that the containment liner plate was designed to withstand the following cyclic loads:

- 40 cycles of annual outdoor temperature variations
- 200 cycles of containment temperature variations from plant startup and shutdown
- 1 cycle of containment temperature variation resulting from accident conditions
- 10 cycles of earthquake loads

The applicant indicated that the fatigue evaluation of the liner plate used an envelope of the design loads. The applicant further showed that the number of allowed cycles for the enveloped design load far exceeds the number projected for 60 years of plant operation.

The applicant discussed the evaluation of the containment penetrations in Section 4.6.2 of the LRA. The applicant indicated that, although mechanical penetrations should have been designed to meet the fatigue provisions of the ASME Code, the original stress analyses of most penetrations address only pipe break loads. The applicant stated that recent analyses of the main steam and RHR penetrations demonstrate that these penetrations satisfy the fatigue exemption provisions of ASME Code, Section III, Paragraph N-415.1. The applicant stated that the number of design cycles used in the evaluation of these penetrations is not expected to be exceeded during the period of extended operation. The applicant indicated that ASME Code, Section XI, will manage fatigue cracking of the remaining penetrations.

4.6.2 Staff Evaluation

RAI 4.6.1-1

Section 4.6.1 of the LRA and Section 5.2.3 of the CNP UFSAR discuss the design of the liner plate. The UFSAR indicated that the liner plate was designed for the cyclic loads as described by the applicant in the LRA. In the LRA, the applicant indicated that the maximum calculated stress resulting from design cyclic loads is relatively low, and, consequently, fatigue of the liner plate is not a concern for the period of extended operation. The applicant also indicated that it evaluated the liner in 1999 after the discovery of localized thinning of the liner. In RAI 4.6.1-1, the staff asked the applicant to indicate the amount and extent of the localized liner thinning. The staff also requested that the applicant describe how it performed the fatigue evaluation of the locally thinned area.

The applicant's June 16, 2004, response indicated that corrosion pitting caused the localized thinning. The observed pitting occurred behind the moisture barrier sealant material used to protect the bottom liner from moisture intrusion in the annulus gap below the floor grade level. The applicant indicated that the observed pitting in the Unit 1 liner exceeded the established acceptance criteria that require a minimum liner plate wall thickness to be greater than 6.2 mm (1/4 in.). The applicant also indicated that the pitting was localized. The NRC documented its review of the applicant's evaluation of the liner and corrective actions in NRC Inspection Reports 50-315/99026(DRS) and 50-316/99026(DRS). The reports conclude that the applicant's corrective actions were adequate.

The applicant's response to RAI 4.6.1-1, indicates that the liner plate is capable of sustaining 180,000 cycles of an alternating stress of 20 kips per square inch (ksi). The value of 20 ksi is the design stress limit for operating conditions specified in the UFSAR. The applicant performed a simplified calculation of the maximum liner stress resulting from the design operating loads and found that the calculated stress was significantly less than 20 ksi. On the basis of this assessment, the applicant concluded that ample fatigue margin exists in the liner plate to accommodate the observed pitting in the liner plate. The staff agrees with the applicant's qualitative assessment that, considering the number of design cycles and the magnitude of the operating stress range, adequate fatigue margin should exist in the liner plate to accommodate the observed pitting. Therefore, the staff finds that the applicant performed an acceptable assessment regarding the fatigue life of the liner plate for the period of extended operation, pursuant to 10 CFR 54.21(c)(1).

RAI 4.6.2-1

As stated previously, the applicant indicated that containment penetrations should satisfy the ASME Code fatigue provisions. However, most of the containment penetration stress analyses address only pipe break loads. The applicant stated that recent analyses of the main steam and RHR penetrations demonstrate that these penetrations satisfy the fatigue exemption provisions of ASME Code, Section III, Paragraph N-415.1. The applicant proposed to manage the potential for fatigue cracking of the remaining penetrations using ASME Code, Section XI. However, the NRC staff has not endorsed the use of the ASME Code, Section XI, inspection program in lieu of meeting design-basis fatigue limits for the period of extended operation. In RAI 4.6.2-1, the staff requested that the applicant either propose a plant-specific fatigue AMP for the penetrations, in accordance with 10 CFR 54.21(c)(1)(iii), or provide an evaluation to demonstrate that the penetrations will be acceptable for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii).

In its June 16, 2004 response, the applicant committed to perform additional evaluations of the containment penetrations before the period of extended operation. The applicant proposed to evaluate containment penetration groups that have similar cyclic loads to demonstrate that these penetration groups satisfy the fatigue exemption provisions of ASME Code, Section III, Paragraph N-415.1. The applicant also committed to perform a fatigue analysis of the limiting penetration for any penetration group that does not satisfy the fatigue exemption rules. The fatigue analysis will be projected to the end of the period of extended operation. This is Commitment # 34 in Appendix A of this SER. The applicant's commitment resolves RAI 4.6.2-1.

4.6.3 UFSAR Supplement

The applicant provided a UFSAR Supplement describing its TLAA evaluation for the containment liner plate and penetration fatigue analyses in Section A.2.2.4 of the LRA. The staff requested that the applicant updating the UFSAR Supplement to reflect its commitment to analyze the containment penetrations. The staff identified this as Confirmatory Item 4.6-1. The applicant's January 21, 2005, response provided the updated UFSAR Supplement for Section A.2.2.4. The updated UFSAR Supplement contains a discussion of the applicant's commitment to analyze the containment penetrations. This is part of Commitment # 34 in Appendix A of this SER. The staff concludes that the revised UFSAR Supplement adequately describes the applicant's actions to address the containment liner plate and penetration fatigue analyses. Therefore, Confirmatory Item 4.6-1 is closed.

4.6.4 Conclusions

The staff has reviewed the applicant's TLAA of the containment liner and penetrations and concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1)(i). The staff has also reviewed the UFSAR Supplement and finds that the applicant's revised UFSAR Supplement provides a sufficient description of the containment liner and penetration fatigue TLAA to satisfy the requirements of 10 CFR 54.21(d).

4.7 Other Plant-Specific Time-Limited Aging Analyses

Other CNP-specific TLAAs include the following:

- leak-before-break analyses
- thermal aging evaluation of the RCP casing
- ice condenser lattice frame fatigue analysis
- underclad cracking
- steam generator flow-induced vibration analysis
- fatigue analysis of cranes

4.7.1 Reactor Coolant System Piping Leak Before Break

4.7.1.1 Summary of Technical Information in the Application

The applicant stated that it had performed a leak-before-break (LBB) analysis for the CNP RCS primary loop and the pressurizer surge line. The analysis considered the thermal aging of cast austenitic stainless steel (CASS) piping and the fatigue transients that drive the flaw growth over the operating life of the plant.

4.7.1.2 Staff Evaluation

The applicant completed a TLAA evaluation of the RCS primary loop piping LBB analyses, and WCAP-15131 documents the evaluation. First, the applicant considered how time would impact the material properties of CASS. The CASS used in the RCS is subject to thermal aging during service. Thermal aging causes an elevation in the yield strength of the material and a decrease in the fracture toughness. The decrease in fracture toughness is proportional to the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation or fully aged point is reached. The applicant stated that Section 4.3 of WCAP-15131 addresses the fracture toughness properties of statically and centrifugally cast CF8M stainless steel. The fracture toughness data from NUREG/CR-6177 was used to calculate the J value for both pipes and elbows. The analysis supporting LBB relied on fully aged stainless steel material properties, and, therefore, the applicant concluded that the analysis does not have a material property time-dependency that requires further evaluation for license renewal.

Second, the applicant considered how time would influence the accumulation of actual fatigue cycles that could invalidate the fatigue crack growth analysis reported in WCAP-15131. The applicant stated that it had performed a fatigue crack growth analysis of the reactor vessel inlet nozzle safe-end region to determine its sensitivity to the presence of small cracks. It selected the nozzle safe-end connection because crack growth calculated at this location is representative of the entire primary loop.

The nozzle safe-end connection configuration includes an SA 508 Class 2 or 3 stainless steel clad nozzle connected to a stainless steel safe end by a nickel-based alloy weld. The applicant obtained the fatigue crack growth rate laws for the stainless steel clad LAS nozzle from ASME Code, Section XI. Fatigue crack growth rate laws for stainless steel and Alloy 600 in a PWR environment were developed based on available industry literature. The applicant stated that had it evaluated the crack growth rate laws for the reactor transients presented in WCAP-15131, Table 8-1, which are bounded by the fatigue design transients defined in Table 4.1-10 of the UFSAR.

The applicant completed its review of the RCS fatigue transient cycle definitions presented in Table 4.1-10 of the UFSAR and found in all instances that the RCS design transients originally defined for 40 years are acceptable for 60 years of operation. In addition, the continued implementation of the Fatigue Monitoring Program provides reasonable assurance that the fatigue crack growth analysis reported in WCAP-15131 will remain valid during the period of extended operation. Based on the information provided above, the staff concludes that the LBB TLAA will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), and is therefore acceptable.

The applicant also completed a TLAA evaluation of the pressurizer surge line LBB analyses, described in WCAP-15435. The applicant stated that the report demonstrates compliance with the LBB criteria for the pressurizer surge line piping based on plant specific analysis. The surge line piping is fabricated from A376, Type 316, wrought austenitic stainless steel, and is not susceptible to reduction of fracture toughness by thermal aging. The applicant reviewed WCAP-15435 and determined that the only analysis consideration that could be influenced by time is the accumulation of actual fatigue transient cycles that could invalidate the fatigue crack growth analysis reported in Section 6.0 of WCAP-15435. A fatigue crack growth analysis was performed for a plant similar to CNP, Units 1 and 2, which evaluated two locations. The results of the analysis indicate that the maximum fatigue crack growth for 40 years is acceptable by ASME Code, Section XI, acceptance standards. Because the pressurizer pipe size, pipe schedule, and pipe materials are the same, and the design transients are identical to the plant used in the analysis, the applicant concluded that CNP, Units 1 and 2, pressurizer surge lines will have similar crack growth. The applicant evaluated the crack growth formulations reported in WCAP-15435 for CNP fatigue design transients defined in Table 4.1-10 of the UFSAR.

The applicant concluded that the results of the RCS transient cycle definition review determined that in all instances the RCS design transients originally defined for 40 years are acceptable for 60 years of operation. Additionally, the applicant considered that the continued implementation of the Fatigue Monitoring Program provides reasonable assurance that the fatigue crack growth analysis reported in WCAP-15435 will remain valid for the period of extended operation. The applicant also stated that the NRC SE of WCAP-15435 relied on the applicant's demonstration that the leakage detection system inside containment could reliably detect 0.8 gallons per minute of primary leakage. In December 2000, an NRC inspection reviewed the engineering evaluation to verify that the radiation monitoring system in the lower containment can detect this leakage using particulate detectors. The applicant stated that the inspection resulted in no significant findings.

4.7.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an UFSAR Supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided an UFSAR Supplement summary description TLAA of the RCS piping LBB in LRA Section A.2.2.5. On the basis of its review, the staff concluded the UFSAR Supplement summary adequately describes the TLAA of the RCS piping LBB and is therefore acceptable.

4.7.1.4 Conclusion

The properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation. The applicant established the Fatigue Monitoring Program to assure that the number of cycle counts for a transient set does not exceed its cycle limits. Therefore, the staff concludes that the applicant has provided an acceptable TLAA regarding LBB and meets the requirements of 10 CFR 54.21(c)(1)(i).

4.7.2 ASME Code Case N-481

4.7.2.1 Summary of Technical Information in the Application

The applicant stated that it performed a demonstration of compliance of the primary loop CASS pump casings with ASME Code Case N-481 for CNP, Units 1 and 2. The CNP analysis considered thermal aging and fatigue crack growth of the CASS pump casings. The applicant stated that these analyses meet the definition of a TLAA.

4.7.2.2 Staff Evaluation

The applicant stated that a demonstration of compliance of the primary loop pump casings with ASME Code Case N-481 was evaluated generically for all Westinghouse plants in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems." Further, WCAP-13128, "Demonstration of Compliance of the Primary Loop Pump Casings of D. C. Cook Units 1 and 2 to ASME Code Case N-481," presents a CNP-specific Code Case N-481 evaluation. The CNP analysis references the generic evaluation of Code Case N-481 provided in WCAP-13045. WCAP-13128 finds that time influences the thermal aging of the CASS pump casings and fatigue crack growth. Therefore, the applicant considered the Code Case N-481 analysis as a potential TLAA at CNP.

RAI 4.7.2.1-1

The applicant's TLAA for ASME Code Case N-481 did not indicate whether the NRC reviewed and approved the generic WCAP-13045 or the CNP-specific WCAP-13128. Therefore, in RAI 4.7.2.1-1, the staff asked the applicant to do the following:

> Provide documentation which identifies that the NRC staff reviewed and approved WCAP-13045 and WCAP-13128. If the reports were not previously submitted, then the applicant is requested to submit WCAP-13045 and WCAP-13128 for NRC review and approval.

In its supplemental letter dated June 16, 2004, the applicant's response to RAI 4.7.2.1-1 stated that WCAP-13045 provides information to demonstrate compliance with item (d) of ASME Code Case N-481 on a generic basis for all Westinghouse design primary loop pump casings. The applicant stated that a variety of pump casing models, loads, and materials exist, and it is not feasible to specifically qualify each plant of Westinghouse design. Instead, it set up enveloping or bounding criteria whereby a specific utility need only show that the loads of the pump casings of interest fall under the umbrella loads established by the analysis.

WCAP-13128 includes the CNP-specific nonproprietary information from WCAP-13045 necessary to support the generic conclusions of the report. The applicant explained that WCAP-13128 qualified the primary loop pump casings of CNP, Units 1 and 2, to item (d) of ASME Code Case N-481 by evaluation. The applicant stated that the North Anna Power Station, Unit 2, also used this same approach as an appendix to its ISI plan for the third inspection interval dated June 30, 2001. The staff concludes that the applicant's response to RAI 4.7.2.1-1 is acceptable. The staff considers RAI 4.7.2.1-1 closed.

In WCAP-13128, the applicant evaluated the material properties of CASS. The applicant stated that CASS is used in the RCS and is subject to thermal aging during service, as discussed in Section 4.7.1.1 of the LRA. The analysis reported in WCAP-13128 supporting ASME Code Case N-481 relied on fully aged stainless steel material properties. Therefore, the applicant concluded that the analysis does not have a material property time-dependency that would require further evaluation for license renewal.

The applicant also completed a stability evaluation of the RCP and concluded that the accumulation of actual fatigue transient cycles over time could invalidate the stability evaluation reported in WCAP-13045, Section 12.0, including Table 12.2. The applicant stated that the Fatigue Monitoring Program, which is discussed in Appendix B to the LRA, monitors thermal fatigue design transients (including the transient cycle assumptions reported in WCAP-13045, Table 12-2) for the period of extended operation. The applicant concluded that the continued implementation of the Fatigue Monitoring Program will provide reasonable assurance that the evaluation results reported in WCAP-13128 will remain valid during the period of extended operation. Therefore, the fatigue growth analysis will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an UFSAR Supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided an UFSAR Supplement summary description of TLAA regarding ASME Code Case N–481 in LRA Section A.2.2.5. On the basis of its review, the staff concluded the UFSAR Supplement summary adequately describes the TLAA regarding ASME Code Case N–481 and is therefore acceptable.

4.7.2.4 Conclusion

The staff has reviewed the information provided in Section 4.7.2 of the LRA, as supplemented by the applicant's response to RAI 4.7.2.1-1 in its letter dated June 16, 2004. This review finds that the applicant demonstrated the compliance of the primary loop CASS pump casings material with ASME Code Case N-481 because the casings will not degrade below the fully aged properties in the extended period of operation. The applicant established the Fatigue Monitoring Program that monitors thermal fatigue design transients and assures that the number of cycle counts for a transient set does not exceed cycle limits. Therefore, the staff concludes that the applicant has provided an acceptable TLAA regarding ASME Code Case N-481 and meets the requirements of 10 CFR 54.21(c)(1)(i).

4.7.3 Ice Condenser Lattice Frame

4.7.3.1 Summary of Technical Information in the Application

In Section 4.7.3 of the LRA, the applicant provided a TLAA related to the ice condenser lattice frames (ICLFs) for Units 1 and 2. The applicant indicated that UFSAR Table 5.3.5.3-2 shows the results of fatigue analysis. The applicant explained that the UFSAR analysis is based on 400 operational basis earthquakes (OBEs). Based on the operating experience at CNP and other facilities, this OBE limit will not be surpassed during the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.3.2 Staff Evaluation

In addition to the review of Section 4.7.3 of the LRA, the staff reviewed Table 3.5.2-1 and the Structures Monitoring Program to see if the applicant addressed aspects related to aging management of ICLF components. The applicant's fatigue analysis only considers the gross effects of number of cycles of OBEs on ICLFs. The staff finds the TLAA related to the number of OBE cycles acceptable, as the number of OBE cycles should be well below 400 throughout the end of the extended period of operation.

However, the LRA does not address the following:

- the operating experience related to the condition of ICLFs
- the effects of borated ice on the ICLF components
- the effects of sustained low temperatures
- fatigue resulting from the number of cycles of temperature transients on the ICLF components.

RAI 4.7.3-1

Therefore, in RAI 4.7.3-1, dated May 7, 2004, the staff stated the following:

> A line item in Table 3.5.2-1 (page 3.5-31) of the LRA, states that the aging effect considered for ICLF is "loss of material," and that it is monitored under Structural Monitoring Program (SMP). A review of the SMP in Section B1.32 of the LRA indicates that the program is consistent with Section XI.S6 of NUREG-1801. NUREG-1801 does not specifically incorporate the aging management of the components of ice condensers. In order to complete the review of this TLAA, the staff requested that the applicant provide the following information:
>
> (a) A summary of operating experience related to the condition of ICLF components (out of plumb support columns, lattice frame spacing adjustments, maintenance of hydraulic radius, etc.).
>
> (b) An assessment of the effects of borated ice and low sustained temperature on ICLF components.
>
> (c) Justification for not considering the fatigue analysis TLAA for the effects of temperature variation on the ICLF components.

In its response to item (a), dated June 16, 2004, the applicant stated the following:

> A search of the electronic corrective action program database for plant specific operating experience over the past five years found only one CR that was related to

the condition of the ice condenser lattice frame structural components. The CR documented damage to ice condenser lattice guide/spacer bars. No CRs were identified pertaining to loss of material or other aging effects for these components. The CR evaluation determined that the bent spacers resulted from maintenance activities while attempting to free frozen ice baskets. In addition, an operating experience review performed during the integrated plant assessment process did not identify aging effects as a problem for ice condenser lattice frame components.

The staff finds that the applicant's operating experience does not indicate any significant age-related degradation that requires specific attention during the period of extended operation. Moreover, the applicant monitors the aging effects under its Structures Monitoring Program.

In its response to item (b), dated June 16, 2004, the applicant provided the following information:

> The ice condenser environment is maintained between -12 °C (10 °F) and -6.7 °C (20 °F) with very low absolute humidity. In this environment, the ice condenser lattice frame components are not susceptible to corrosion. The materials of ice condenser construction were selected to be effectively inert under all conditions of operation of the ice condenser. The ice condenser lattice frame structural sections, plates and bar flats, are made of high-strength low-alloy weathering grade steel, meeting the requirements of ASTM A441, Standard Specification for High-Strength Low-Alloy Structural Manganese Vanadium Steel. Weathering steel exhibits excellent corrosion resistance. Consequently, the aging effects of borated ice and low sustained temperature on the ice condenser lattice frames are expected to be insignificant. This determination is substantiated by CNP operating experience. However, loss of material is conservatively considered an aging effect requiring management.

Based on the material of construction of the ICLFs and demonstration that the ICLF has not experienced loss of material, the staff concurs with the applicant's approach to monitor the age-related degradation of ICLF components, including the effects of low temperature cycles and borated ice during the period of extended operation.

In its response to item (c), dated June 16, 2004, the applicant provided the following information:

> The lattice frame is designed according to American Institute of Steel Construction (AISC) AISC 69, Specification for Design, Fabrication, and Erection of Structural Steel for Buildings. The design loading conditions for the lattice frames are specified in UFSAR Section 5.3.4.2 and include dead weight, live loads, thermal-induced loads, seismic, and DBA loads transferred to the columns by the intermediate deck and doors. The ambient temperature variation under normal operating conditions is -12 °C (10 °F).
>
> The fatigue evaluation of the lattice frame was conducted in accordance with AISC 69, Appendix B. Thermal loads due to the maximum temperature are considered in the evaluation of maximum stresses reported in UFSAR Table 5.3.5.3-1, as required by AISC 69.

The fatigue stresses applicable to the lattice frame due to 400 operating basis earthquake (OBE) cycles were determined to be below the allowable range of stress defined by AISC 69, as indicated in UFSAR Table 5.3.5.3-2. Due to the relatively low magnitude of repeated temperature variations, thermally induced loads are less limiting than OBE loads when considering repeated variations of loads on the structure (fatigue).

Based on the applicant's responses to items (a), (b), and (c), above, the staff concludes that the applicant will appropriately manage the aging of the ICLF components during the extended period of operation.

4.7.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an UFSAR Supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided an UFSAR Supplement summary description of the TLAA of ICLF components in LRA Section A.2.2.5. On the basis of its review, the staff concluded the UFSAR Supplement summary adequately describes the TLAA of ICLF components and is therefore acceptable.

4.7.3.4 Conclusion

Based on the staff's review of Section 4.7.3 of the LRA and the applicant's response to the RAI, the staff concludes that the existing fatigue analysis is valid for the ICLF members, in accordance with 10 CFR 54.21(c)(1)(i). Based on the applicant's commitment to monitor the ICLF members under its Structures Monitoring Program, the staff also concludes that the ICLF members will be able to perform their intended function during the period of extended operation.

4.7.4 Reactor Vessel Underclad Cracking

4.7.4.1 Summary of Technical Information in the Application

In 1970, examination of Nucleoelectrica Argentina SA's Atucha-1 reactor vessel first detected intergranular separations (underclad cracking) in LAS, heat-affected zones under austenitic stainless steel weld claddings in SA-508, Class-2, reactor vessel forgings. Such separations have been reported in SA-508, Class 2, reactor vessel forgings manufactured to a coarse-grain practice and clad by high-heat input submerged arc processes. The regulatory position regarding this issue, found in RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components," issued May 1973, states that detection of underclad cracks "normally requires destructively removing the cladding to the weld fusion line and examining the exposed base metal either by metallographic techniques or with liquid penetrant or magnetic particle testing methods."

WCAP-7733, "Reactor Vessels Weld Cladding—Base Metal Interaction," in which Westinghouse presents a fracture mechanics analysis to justify continued operation of Westinghouse units for 32 EFPYs with underclad cracks in the RPVs, provides a detailed analysis of underclad cracks. The WOG and the NRC identified the analysis reported in WCAP-7733 as a TLAA requiring evaluation for license renewal. The WOG subsequently evaluated the impact of cracks beneath austenitic stainless steel weld cladding on RPV integrity in WCAP-15338, which the NRC approved in July 2002 to include all Westinghouse plants.

The CNP reactor vessels do not contain SA 508, Class 2, forgings in the beltline regions. Only the vessel and closure head flanges and inlet and outlet nozzles are fabricated from SA 508, Class 2, forgings. The evaluation contained in WCAP-15338 has been used to demonstrate that fatigue growth of the subject flaws will be minimal over 60 years and the presence of the underclad cracks are of no concern relative to the structural integrity of the vessels.

Table 4.1-10 of the UFSAR reports the design transients for CNP. The numbers of design cycles and transients assumed in the WCAP-15338 analysis bound the numbers of design cycles and transients projected for 60 years of operation. The UFSAR Supplement, which is Appendix A to the application, provides a summary description of the evaluation of the TLAA for reactor vessel underclad cracking.

Therefore, the applicant concluded that the analysis of underclad cracking for CNP would remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.4.2 Staff Evaluation

Underclad cracks, first discovered in October 1970 during examination of the Atucha reactor vessel, have been reported to exist only in SA-508, Class 2, RPV forgings manufactured with a coarse-grain microstructure and clad by high-heat input submerged arc welding processes. WCAP-7733 first addresses the underclad cracking issue and justifies the continued operation of Westinghouse plants for 32 EFPYs. Subsequently, Westinghouse submitted WCAP-15338-A, which extends the analysis to justify operation of Westinghouse plants for 60 years of plant operation. The staff providesdits review of WCAP-15338-A in a September 25, 2002, letter to R.A. Newton concluding that LRAs should include the following two action items:

(1) The license renewal applicant should verify that its plant is bounded by the WCAP-15338-A report. Specifically, the renewal applicant should indicate whether the number of design cycles and transients assumed in the WCAP-15338-A analysis bounds the number of cycles for 60 years of operation of its RPV.

(2) As required by 10 CFR 54.21(d), a UFSAR Supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of the TLAA for the period of extended operation. Those applicants for license renewal referencing the WCAP-15338-A report for the RPV components must ensure that the UFSAR Supplement summarizes the evaluation of the TLAA.

RAI 4.7.4-1

The NRC SE for WCAP-15338-A requires the applicant to verify that its plant is bounded by the values in the report. In LRA Section 4.7.4, the applicant stated that the number of design cycles and transients assumed in the WCAP-15338-A analysis bounds the number of design cycles and transients for CNP units for 60 years. The applicant did not, however, explain how it arrived at this conclusion. The NRC requested this information in RAI 4.7.4-1. The applicant responded in a letter dated September 2, 2004, that, except for the feedwater cycling at hot shutdown, it has verified that the design transients assumed in WCAP-15338-A bound the types and numbers of RCS design transients for 60 years, as shown in LRA Table 4.3-1. The feedwater cycling at hot shutdown transient is associated with a concern about feedwater nozzle cracking and is not monitored at the CNP units because of design and operating modifications to preclude feedwater nozzle cracking. The staff considers the response acceptable because the types and numbers of CNP RCS design transients for 60 years are appropriate as discussed in Section 4.3 of this SER, and the applicant has satisfied action item 1 of the SE for WCAP-15338-A discussed above, demonstrating that the types and numbers of CNP RCS design transients for 60 years are bounded by those assumed in WCAP-15338-A. High-cycle-fatigue initiation and low-cycle-fatigue growth caused feedwater nozzle cracking. By the mid-1980s, design and operating modifications that precluded feedwater nozzle cracking had resolved this generic issue which affected feedwater inner radii and spargers. Therefore, the staff agrees with the applicant that the CNP units need not monitor the feedwater cycling at hot shutdown transient for the concern of underclad cracking and determines that the conclusions of WCAP-15338-A apply to the CNP units. Therefore, RAI 4.7.4-1 is closed.

4.7.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an UFSAR Supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided an UFSAR Supplement summary description of the TLAA for RPV underclad cracking in LRA Section A.2.2.5. On the basis of its review, the staff concluded the UFSAR Supplement summary adequately describes the TLAA for RPV underclad cracking and is therefore acceptable.

4.7.4.4 Conclusion

The staff reviewed the TLAA regarding the structural integrity of the CNP RPVs with assumed underclad cracking during the period of extended operation. The staff determined that the conclusions of WCAP-15338-A apply to the CNP RPVs and the flaw growth resulting from 60 years of operation will not result in the loss of integrity of the CNP RPVs to the end of the period of extended operation. Therefore, this analysis satisfies the requirements of 10 CFR 54.21(c)(1)(i).

4.7.5 Steam Generator Tube Flow-Induced Vibration

4.7.5.1 Summary of Technical Information in the Application

In the LRA, the applicant identified analyses of steam generator tube flow-induced vibrations (FIVs) as a TLAA. The steam generators were replaced in 2000 for Unit 1 and 1988 for Unit 2. The applicant's analyses were based on the use of fretting wear damage parameters and corrosion allowance assumptions for Unit 1 and tube wear allowance assumptions for Unit 2. The analyses for Units 1 and 2 remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

4.7.5.2 Staff Evaluation

The original steam generators were replaced in 2000 for Unit 1 and 1988 for Unit 2. The applicant analyzed flow-induced vibrations as part of the steam generator analysis for license renewal. In response to RAI 4.7.5-1, the applicant stated that different assumptions were made for FIV analyses performed by two different vendors. The Unit 1 FIV analysis is based on a 40-year design life, extending to 2040, which surpasses the period of extended operation. For Unit 2, the assumption for wear allowance was based on designed set of operating transients which are monitored through the Fatigue Monitoring Program. In Section A.2.2.2 of the LRA, the applicant states that the assumed number of RCS design transients is acceptable for 60 years. Steam generators are designed to limit tube degradation resulting from FIV. Steam generator tubes are supported to minimize excessive vibration which could be detrimental to their structural integrity. The impact of FIV will most likely cause tube wear at the intersection of AVBs and other supports with the tubes. The applicant further states in their response that the Steam Generator Integrity Program, which is based on NEI 97-06, "Steam Generator Program Guidelines," and the Water Chemistry Control Program, which is based on EPRI guidelines TR-105714, Revision 4 and TR-102134, Revision 5, manage the aging effect of loss of material of steam generator tubes and tubes support components. This includes loss of material by the aging mechanisms of corrosion and wear.

Despite operating experience showing that corrosion and wear rates of steam generator tubes can exceed the rates predicted by these analyses, the staff agrees with the applicant that the Water Chemistry Program and periodic inspections as required by the Steam Generator Tube Integrity Program will manage these aging effects. These periodic inspections will monitor and detect any potential aging effects resulting from corrosion and tube wear. These programs are consistent with the AMP descriptions in the GALL Report and are acceptable. Staff evaluations of these AMPs and aging effects appear in Sections 3.0.3.2.15, 3.0.3.1, and 3.1.2.3.5 of this SER. The staff therefore concludes that tube corrosion and wear in CNP are not TLAAs.

4.7.5.3 UFSAR Supplement

The applicant provided the UFSAR Supplement summary descriptions for the TLAA on the Steam Generator Tubes - Flow Induced Vibration in Section A.2.2.5 of Appendix A to the LRA. The staff reviewed the UFSAR Supplement summary descriptions for the TLAA, as given in Section A.2.2.5 of Appendix A to the LRA. The staff determined that the steam generator FIV analysis may not be considered a TLAA because other periodic inspections programs can better manage the aging effects of tube corrosion and wear; therefore, the UFSAR description of the FIV analysis is not required.

4.7.5.4 Conclusion

The staff concludes that the flow-induced vibration analysis for the replacement steam generators may not be considered a TLAA issue as defined in 10 CFR 54.3(a)(3). The applicant will adequately manage the effects of aging on the pressure boundary function for the period of extended operation through periodic inspections required by the applicant's Steam Generator Integrity Program.

4.7.6 Fatigue Analysis of Cranes

The following types of cranes within the scope of license renewal were designed in accordance with the guidance contained in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants":

- containment polar cranes
- auxiliary building cranes
- screen house crane

According to NUREG-0612, the design of heavy-load, overhead handling systems must meet the intent of the Crane Manufacturers Association of America (CMAA) Specification Number 70, "Specifications for Electric Overhead Traveling Cranes." Overhead cranes designed to CMAA-70 have an implicit fatigue design basis equivalent to a limiting number of 100,000 load cycles.

4.7.6.1 Summary of Technical Information in the Application

In response to NUREG-0612, the applicant stated that the polar cranes, auxiliary building cranes, and screen house crane were in compliance, with limited exceptions, with the design standards of CMAA-70. Conservative estimates of the number of cycles that could be achieved in 60 years of operation for these five cranes do not exceed the limit in CMAA-70. Therefore, the applicant contended that the crane designs will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.6.2 Staff Evaluation

The NRC approved the applicant's response to NUREG-0612 in an SE dated September 20, 1983. Based on a review of the estimate of the number of load cycles projected for 60 years of operation for the above listed cranes, the staff finds that these canes will meet the load cyclic requirements of CMAA-70 with adequate safety margins. Therefore, the applicant has demonstrated that the TLAA for the current operating term remains valid for the period of extended operation.

4.7.6.3 UFSAR Supplements

As required by 10 CFR 54.21(d), applicants for license renewal must include an UFSAR Supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided an UFSAR Supplement summary description of the fatigue load cycles TLAA for cranes in LRA Section A.2.2.5. On the basis of its review, the staff concluded the UFSAR Supplement summary adequately describes the fatigue load cycles TLAA for cranes and is therefore acceptable.

4.7.6.4 Conclusions

The staff has reviewed the applicant's crane loads fatigue cycles TLAA and concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1).

4.7.7 Reactor Coolant Pump Flywheels

4.7.7.1 Summary of Technical Information in the Application

The applicant stated that it performed a TLAA on the RCP flywheels. It identified the aging effect of concern to be fatigue crack and growth in the flywheel bore keyway resulting from stresses caused by starting the motor.

4.7.7.2 Staff Evaluation

The applicant stated that the RCP motors are large, vertical, squirrel-cage, induction motors. The motors have flywheels to increase rotational inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The applicant stated that the flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. The applicant identified the aging effect of concern as fatigue crack initiation and growth in the flywheel bore keyway from stresses resulting from starting the motor.

The applicant stated that it submitted a license amendment request in 1996 to reduce the RCP flywheel inspection frequency and scope based on WCAP-14535. This topical report includes a stress and fracture evaluation that addresses fatigue crack growth for 60 years. The applicant also stated that the NRC approved the license amendment requests for CNP, Units 1 and 2, by means of License Amendments 217 and 201.

Since the analysis of fatigue crack initiation and growth in WCAP-14535 is based on a 60-year term, in accordance with 10 CFR 54.21(c)(1)(i), the analysis is acceptable for the extended period of operation.

4.7.7.3 UFSAR Supplement

Section A.1.2 , page A-8, of Appendix A to the LRA provides a UFSAR summary description of the RCP flywheel TLAA, as required by 10 CFR 54.21(d). It indicates that the existing analysis is valid for the period of extended operation and is consistent with the staff's evaluation discussed in Section 4.7.7.2 of this SER. On the basis of its review, the staff concludes the UFSAR Supplement summary adequately describes the TLAA of RCP flywheels and is therefore acceptable.

4.7.7.4 Conclusions

The RCP flywheels are acceptable because the applicant has demonstrated that fatigue crack growth in the flywheel bore keyway from stresses resulting from starting the motor will not exceed the ASME Code requirements during the extended period of operation. In August 1997, the NRC reviewed and approved WCAP-14535, which provided a stress and fracture evaluation that addressed fatigue crack growth for 60 years. Therefore, the staff concludes that the applicant has provided an acceptable TLAA for RCP flywheels and meets the requirements of 10 CFR 54.21(c)(1)(i).

4.8 Conclusions for TLAAs

The staff reviewed the information in Section 4 of the LRA. On the basis of its review, the staff concludes that the applicant provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concludes that the applicant has demonstrated the following:

- The TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i).
- The TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii).
- The aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii).

In addition, the staff concludes that there are no plant-specific exemptions in effect that are based on TLAAs, as required by 10 CFR 54.21(c)(2). On this basis, the staff concludes that the structures and components subject to TLAAs 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).

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 license for the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, on December 21, 2004. On February 9, 2005, the applicant presented its license renewal application, and the staff presented its review findings to the Advisory Committee on Reactor Safeguards (ACRS) Plant License Renewal Subcommittee. The staff reviewed the applicant's comments on the SER with Open 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 May 29, 2005.

During the 524th meeting of the ACRS, July 6-8, 2005, the ACRS completed its review of the CNP license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated July 18, 2005. A copy of this letter is provided on the following pages of this SER Section.

July 18, 2005

The Honorable Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 2005-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE DONALD C. COOK NUCLEAR PLANT, UNITS 1 AND 2

Dear Chairman Diaz:

During the 524th meeting of the Advisory Committee on Reactor Safeguards, July 6-8, 2005, we completed our review of the license renewal application for the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, and the final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during a meeting on February 9, 2005. During these reviews, we had the benefit of discussions with representatives of the NRC staff and Indiana Michigan Power Company, the applicant. We also had the benefit of the documents referenced. This report fulfills the requirements of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

CONCLUSION AND RECOMMENDATION

1. The programs committed to and established by the applicant to manage age-related degradation provide reasonable assurance that CNP Units 1 and 2 can be operated in accordance with their current licensing basis for the period of extended operation without undue risk to the health and safety of the public.

2. The Indiana Michigan Power Company's application for renewal of the operating licenses for CNP Units 1 and 2 should be approved.

BACKGROUND AND DISCUSSION

CNP Units 1 and 2 are Westinghouse pressurized water reactors with ice condenser containment buildings. Licensed power output is 3304 MWt for Unit 1 and 3468 MWt for Unit 2. The Indiana Michigan Power Company requested renewal of the operating licenses of Units 1 and 2 for 20 years beyond their current license terms, which expire on October 25, 2014 and December 23, 2017, respectively.

In the final SER, the staff documented its review of the license renewal application and other information submitted by the applicant and obtained during the staff's audits and inspections at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs; and the identification and assessment of time-limited aging analyses (TLAAs).

The CNP application demonstrates consistency with, or justifies deviations from, the approaches specified in the Generic Aging Lessons Learned Report.

During its review, the staff identified several components that should have been included in the scope of license renewal. The applicant brought them into scope. With these inclusions, the staff concluded that the applicant's scoping and screening processes have successfully identified the SSCs within the scope of license renewal and subject to an aging management review. We agree.

The applicant performed a comprehensive aging management review of all SSCs within the scope of license renewal. The application contains descriptions of 46 aging management programs for license renewal, including existing, enhanced, and new programs. We agree with the staff's conclusion that these programs are adequate and consistent with accepted practices for aging management.

To be effective, the aging management programs need to be appropriately implemented. During the aging management program inspections, the staff found that walkdowns performed as part of the System Walkdown Program were not conducted quarterly as stated in the license renewal application. Also, the applicant noted that it had not evaluated two coupons from the Boral Surveillance Program. This program monitors the performance of absorber materials in the spent fuel pool by periodically measuring the physical and chemical properties of coupon samples that receive a higher radiation dose than the functional boral panels. The applicant has implemented corrective actions to ensure that the commitments will not be missed in the future.

The applicant identified and reevaluated systems and components requiring TLAAs for 20 more years of operation. Analyses of reactor vessel neutron embrittlement (upper shelf energy, pressurized thermal shock screening criteria, and pressure-temperature limits) performed by the applicant and independently verified by the staff demonstrate that the limiting reactor vessel beltline materials will satisfy the acceptance criteria for the period of extended operation.

The applicant showed that the current fatigue analysis of the ice condenser lattice frame, which conservatively assumes 400 operating basis earthquakes, bounds 60 years of operation. This analysis also bounds the effects of loads due to temperature fluctuations. The Structures Monitoring Program manages aging of this structure. Operating experience indicates that the lattice frame is not subject to significant age-related degradation.

The final SER documents the closure of confirmatory items addressing fatigue of Class 1 components. These confirmatory items were closed by the applicant's commitments to perform additional actions to address fatigue of the auxiliary spray line piping and environmentally assisted fatigue of the pressurizer surge line, safety injection nozzles, charging nozzles, and residual heat removal line. These commitments will ensure that the effects of fatigue are appropriately managed.

Reactor vessel head inspections identified flaw indications in two nozzle penetrations of Unit 2. Weld repairs were performed. No leakage was identified in the reactor vessel head penetrations of Unit 1. Both reactor vessel heads are scheduled for replacement by 2007. Inspections of bottom-mounted instrumentation nozzles in both units have not identified any leakage, and the applicant has committed to follow the recommendations the industry is developing for aging management of Alloy 600 components.

No issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) preclude renewal of the operating licenses for CNP Units 1 and 2. The programs committed to and established by the applicant provide reasonable assurance that CNP Units 1 and 2 can be operated in accordance with their current licensing basis for the period of extended operation without undue risk to the health and safety of the public. The application for renewal of the operating licenses for CNP Units 1 and 2 should be approved.

Sincerely

/RA/

Graham B. Wallis
Chairman

References

1. Indiana Michigan Power Company, "Donald C. Cook Nuclear Plant License Renewal Application," October 2003
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2," May 2005
3. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report with Open Items Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2," December 2004
4. U.S. Nuclear Regulatory Commission, "Donald C. Cook Nuclear Power Plant, Units 1 and 2 NRC License Renewal Scoping/Screening Inspection Report 05000315/2004003 (DRS); 05000316/2004003 (DRS)," June 22, 2004
5. U.S. Nuclear Regulatory Commission, "D.C. Cook Nuclear Power Plant, Units 1 and 2 NRC Aging Management Program Inspection Report No. 05000315/2004013 (DRS); 05000316/2004013 (DRS)," January 10, 2005
6. Information Systems Laboratories, Inc., "Audit and Review Report for Plant Aging Management Reviews and Programs, Donald C. Cook Nuclear Plant, Units 1 & 2," September 22, 2004

6. CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC or the Commission) reviewed the license renewal application for the Donald C. Cook Nuclear Plant, Units 1 and 2, in accordance with Commission regulations and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued July 2001. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29), "Standards for the Issuance of a Renewed License," provides the standards for the issuance of a renewed license.

On the basis of its evaluation of the license renewal application as discussed above, the NRC staff has determined that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that the requirements of Subpart A of 10 CFR Part 51 regarding the Donald C. Cook Nuclear Plant, Units 1 and 2, are documented in Supplement 20 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Donald C. Cook Nuclear Plant, Units No. 1and 2, Final Report," dated May 2005.

APPENDIX A
COMMITMENTS FOR LICENSE RENEWAL

During the review of the Donald C. Cook Nuclear Plant License Renewal Application by the U. S. Nuclear Regulatory Commission staff, the applicant made additional commitments to provide aging management programs to manage the aging effects of structures and components prior to the extended period of operation, as well as other information. The following table lists these commitments, along with the implementation schedule and the source of the commitment.

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
1	The Alloy 600 Aging Management Program will be implemented prior to the period of extended operation. This program will manage aging effects of Alloy 600/690 components and Alloy 52/152 and 82/182 welds in the reactor coolant system that are not addressed by other aging management programs. This program will detect primary water stress corrosion cracking prior to the loss of component intended function by using the examination and inspection requirements specified in American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.1 *See also Item 2 below for changes in the implementation schedule and Item 3 for additional discussion related to this commitment.*
2	The Alloy 600 Aging Management Program commitment will also be revised to indicate that an inspection plan will be submitted for staff review and approval 3 years prior to the period of extended operation to determine if the program demonstrates an ability to manage the effects of aging pursuant to 10 CFR 54.21(a)(3).	Unit 1: October 25, 2011 Unit 2: December 23, 2014	ML042470410 08/11/2004 Attachment 2 RAI B.1.1.2-1	B.1.1

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
3	I&M will continue to participate in industry initiatives, such as the Westinghouse Owners Group and the Electric Power Research Institution (EPRI) Materials reliability Program (MRP). Susceptibility rankings and program inspection requirements regarding Alloy 82/182 pipe butt welds will be consistent with the later version of the EPRI MRP safety assessment or its successors.	Unit 1: October 25, 2011 Unit 2: December 23, 2014	ML042470410 08/11/2004 Attachment 2 RAIs B.1.1.2-1 and B.1.1.2-3	B.1.1
4	The Boric Acid Corrosion Prevention Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.M10. The program will be enhanced to include the attributes documented in LRA, Section B.1.4, Page B-26. The following enhancements to the Boric Acid Corrosion Prevention Program will be implemented prior to the period of extended operation: • The program scope will be revised to address electrical components in addition to ferrite steel. • The program acceptance criteria will be revised to address electrical components in addition to ferrite steel.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.4

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
5	The Buried Piping Inspection Program will be implemented prior to the period of extended operation. The program will include (a) preventive measures to mitigate corrosion, and (b) periodic inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel piping and tanks. Preventive measures will be in accordance with standard industry practice for maintaining external coatings and wrappings. Buried piping and tanks including buried piping and tanks constructed from carbon steel and iron that are not within the scope of license renewal will be inspected when they are excavated during maintenance. Deficiencies associated with out-of-scope piping and tanks will be evaluated for extent of condition, as applicable, to in-scope buried piping and tanks. The Buried Piping Inspection Program will be consistent with, but include an exception to, the program described in NUREG-1801, July 2001, Section XI.M34, as documented in LRA, Section B.1.6, Page B-31.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.6

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
6	The Cast Austenitic Stainless Steel (CASS) Evaluation Program will be implemented prior to the period of extended operation. The program will include a determination of the susceptibility of the CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. Prior to the period of extended operation, CNP will develop aging management program details (*e.g.*, plans for additional volumetric inspections or flaw tolerance evaluations) for the reactor coolant system piping heats of material that are susceptible to reduction of fracture toughness. The CASS Evaluation Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.M12, as documented in LRA, Section B.1.7, Page B-33.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.7

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
7	The Fire Protection Program will be consistent with, but include exceptions to, the program described in NUREG-1801, July 2001, Section XI.M26, as documented in LRA, Section B.1.11.1, Pages B-42 to B-44. The program will be enhanced to include the attributes documented in LRA, Section B.1.11.1, Pages B-45 and B-46. The following enhancements to the Fire Protection Program will be implemented prior to the period of extended operation: • In the carbon dioxide (CO_2) and halon procedures, ensure that conditions that may affect the performance of the system (such as corrosion, mechanical damage, or damage to dampers) are observed and degraded conditions are addressed by means of the Corrective Action Program. • Enhance procedures to ensure the diesel fuel supply line is monitored for degradation during performance testing.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.11.1

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
8	The Fire Water System Program will be consistent with, but include exceptions to, the program described in NUREG-1801, July 2001, Section XI.M27, as documented in LRA, Section B.1.11.2, Pages B-47 and B-48. The program will be enhanced to include the attributes documented in LRA, Section B.1.11.2, Page B-49. The following enhancements will be implemented prior to the period of extended operation: • A sample of sprinkler heads will be inspected using the guidance of the National Fire Protection Act (NFPA) document NFPA 25, Section 2.3.3.1. • The Fire Water System Program will be enhanced to perform non-intrusive measurement of pipe wall thickness based on the NRC interim staff guidance 4 (ISG-4). (ADAMS Accession No. ML023440137)	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.11.2
9	The Heat Exchanger Monitoring Program will be implemented prior to the period of extended operation. The program will inspect heat exchangers for degradation using non-destructive examinations, such as eddy current inspections or visual inspections, or if appropriate, the heat exchanger will be replaced. If degradation is found, an evaluation will be performed to determine its effects on the heat exchanger design functions.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.13

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
10	The following enhancements to the Inservice Inspection (ISI) – ASME Section XI, Augmented Inspections Program will be implemented prior to the period of extended operation: • An augmented ISI volumetric inspection of the spray additive tanks and the portions of the containment spray system that are wetted by sodium hydroxide. • An augmented ISI volumetric inspection of the portions of the discharge header in containment that may contain water with concentrated contaminants.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.18
11	The following enhancement to the Instrument Air Quality Program will be implemented prior to the period of extended operation: • Enhance the CNP Program procedure prior to the period of extended operation to clearly specify frequencies for the dewpoint and dryer tours.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.19

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
12	The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that will be implemented prior to the period of extended operation. This program applies to inaccessible (e.g., in conduit or direct-buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with applied voltage. This program will test these cables to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test. The Non-EQ Inaccessible Medium-Voltage Cable Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.E3, as documented in LRA Section B.1.20, Page B-71.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.20

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
13	The Non-EQ Instrumentation Circuits Test Review Program will be implemented prior to the period of extended operation. The electrical cables included in the scope of this program meet all of the following criteria: • not subject to the EQ requirements of 10 CFR 50.49, • used in instrumentation circuits with sensitive, high-voltage, low-level signals, and • exposed to adverse localized environments caused by heat, radiation, or moisture This program will be consistent with the program described in NUREG-1801, Section XI.E2, with the exception noted in the LRA Section B.1.21, Pages B-72 and B-73.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.21

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
14	The Non-EQ Insulated Cables and Connections Program will be implemented prior to the period of extended operation. The Non-EQ Insulated Cables and Connections Program will apply to accessible insulated cables and connections installed in structures within the scope of license renewal and prone to adverse localized environments. The Non-EQ Insulated Cables and Connections Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.E1, as documented in LRA Section B.1.22, Page B-74.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.22

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
15	The following enhancements to the Pressurizer Examinations Program will be implemented prior to the period of extended operation: • The condition of the internal spray head, spray head locking bar, and coupling will be determined by a one-time visual examination (VT-3) of these components in one CNP unit. This examination will be performed to accepted ASME Section XI methods and standards to ensure that degradation of these items has not occurred. • If flaws are detected in the spray head, spray head locking bar, or coupling, engineering analysis will be completed to determine corrective actions which could include replacement of the spray head. The need for subsequent inspections will be determined after the results of the initial inspection are evaluated.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.24

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
16	The Preventive Maintenance Program will be enhanced to include the attributes documented in LRA Section B.1.25, Pages B-86 and B-87, and as amended in the supplemental response to RAI 2.3.3.8-6. The following enhancements to the Preventive Maintenance (PM) Program will be implemented prior to the period of extended operation: • Revise PM tasks for the emergency diesel generator (EDG) ventilation system to include inspection of the flex joints; for the control room ventilation air handler packages to include inspection of the heat exchanger tubes and flex joints; and for the auxiliary feedwater pump room cooling units to include inspection of the internal evaporator tubes, valves and tubing. • The PM program will manage the aging effects for the emergency diesel engine elastomer flex hoses or tubing, reactor coolant pump lube oil leakage collection components, rubber hoses in the compressed air system, rubber hoses in the Post-Accident Containment Hydrogen Monitoring System reagent gas supply, security diesel engine elastomer flex hoses or tubing, and elastomer condensate storage tanks floating head seals.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.25 *See Item 37 for the amendment to this commitment provided in the supplemental response to RAI 2.3.3.8-6.*

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
17	The Reactor Vessel Integrity Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.M31. The program will be enhanced to include the attributes documented in LRA Section B.1.26, Page B-89. The following enhancements to the Reactor Vessel Integrity Program will be implemented prior to the period of extended operation: • I&M will pull and test one additional standby capsule for each unit between 32 effective full-power years (EFPYs) and 48 EFPYs to cover the peak fluence expected at 60 years. A fluence update will be performed at approximately 32 EFPYs when Capsules W (Unit 1) and S (Unit 2) are pulled and tested. A subsequent fluence update will be performed when the standby capsules are pulled and tested between 32 EFPYs and 48 EFPYs. • Modifications to design and operation that result in changes to the neutron energy spectrum or operating temperatures will be compared to the original environment in which the capsules were irradiated.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.26

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
18	The Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program commitment will be revised to indicate that the program to manage void swelling will be submitted for staff review and approval 3 years prior to the period of extended operation.	Unit 1: October 25, 2011 Unit 2: December 23, 2014	ML042390469 08/19/2004 Attachment 2 RAI B.1.27-2	B.1.27 *This commitment has been superseded by Item 36.*
19	The Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program is a new program that will be implemented prior to the period of extended operation. This program will include visual inspections and non-destructive examinations of the reactor vessel internals during the period of extended operation. A visual inspection will be performed on plates, forgings, and welds to detect and monitor cracking caused by Irradiation Assisted Stress Corrosion Cracking enhanced by reduction of fracture toughness by irradiation embrittlement and distortion due to swelling. For baffle bolts, a volumetric inspection of critical locations will be performed to assess cracking. I&M will participate in industry-wide programs designed by the pressurized water reactor (PWR) Materials Reliability Project Issues Task Group for investigating the impacts of aging on PWR vessel internal components.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.27 *See also Item 36 below for changes in the implementation schedule*

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
20	The Reactor Vessel Internals CASS Program will be implemented prior to the period of extended operation. This program will provide visual inspections and non-destructive examinations of the reactor vessel internals during the period of extended operation. The program will monitor propagation of cracks from existing flaws. In addition to the features of the program described in NUREG-1801, Section XI.M13, the program will manage the aging effect of distortion due to void swelling of the reactor vessel internals. Applicable components will be determined based on the neutron fluence and thermal embrittlement susceptibility of the component. I&M will participate in industry-wide programs designed by the pressurized water reactor (PWR) Materials Reliability Project Issues Task Group for investigating the impacts of aging on PWR vessel internal components.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.28

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
21	The Service Water System Reliability Program will be consistent with, but include exceptions to, the program described in NUREG-1801, July 2001, Section XI.M20, as documented in LRA, Section B.1.29, Pages B-95 and B-96. The program will be enhanced to include the attributes documented in LRA Section B.1.29, Page B-96. The following enhancements to the Service Water System Reliability Program will be implemented prior to the period of extended operation: • The Service Water System Reliability Program will be enhanced to check for selective leaching during visual inspections. • Develop new PM activity or revise existing PM activity to ensure the 8-inch expansion joints in the essential service water supply lines to the EDG heat exchangers are inspected for evidence of loss of material, change in material properties, and cracking.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.29

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
22	The Small Bore Piping Program will be implemented prior to the period of extended operation. The small bore piping inspection will involve a one-time volumetric examination of susceptible items in selected locations of Class 1 small bore piping. These inspections will occur at or near the end of the initial operating period for CNP Units 1 and 2.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.30
23	The Structures Monitoring Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.S6. The program will be enhanced to include the attributes documented in LRA Section B.1.32, Pages B-101 and B-102. The following enhancements to the Structures Monitoring Program will be implemented prior to the period of extended operation: • Include the following in the Structures Monitoring Program — equipment supports, instrument panels, racks, cable trays, conduits, cable tray supports, conduit supports, elastomers, pipe hangers/supports, fire protection pump house superstructure and walls, gas bottle storage tank rack and foundation, security diesel generator room, switchyard control house, fire protection water storage tank foundation, primary water storage tank foundation, and the roadway west of the screenhouse.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.32

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
24	The Structures Monitoring - Crane Inspection Program will be consistent with, but include exceptions to, the program described in NUREG-1801, July 2001, Section XI.M23, as documented in LRA Section B.1.33, Page B-104. The program will be enhanced to include the attributes documented in LRA Section B.1.33, Page B-105. The following enhancements to the Crane Inspection Program will be implemented prior to the period of extended operation: • Develop procedures or recurring tasks to (1) evaluate the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of in-scope cranes, (2) verify that in-scope crane rails and structural components are visually inspected on a routine basis for loss of material, and (3) verify that significant visual indications of loss of material due to corrosion or wear are evaluated according to applicable industry standards and good industry practice.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.33

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
25	The Structures Monitoring - Masonry Wall Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.S5. The program will be enhanced to include the attributes documented in LRA Section B.1.36, Page B-112. The following enhancement to the Masonry Wall Program will be implemented prior to the period of extended operation: Include the following in the Masonry Wall Program: • 4-hour fire-rated masonry block in the turbine building and screenhouse • Masonry block in the auxiliary building Enhancement of the Masonry Wall Program will include enhancement of the Plant Structures Performance Evaluation and Monitoring Program procedure to specify that the following masonry walls are within the scope of this procedure: • Masonry Walls in the auxiliary building that perform a license renewal intended function • Fire-rated masonry walls in the turbine building and screenhouse	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.36

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
26	The System Testing Program will be enhanced to include the attributes documented in LRA Section B.1.37, Pages B-114 through B-118, as clarified below. The following enhancements will be implemented prior to the period of extended operation: • Develop a preventive maintenance (PM) procedure to inspect the centrifugal charging pumps minimum flow orifices and the Unit 1 centrifugal charging pumps discharge orifices. The PM will include ensuring that internal erosion of the orifices would be detected by inspections. • Ensure procedures for engineered safety features ventilation unit, the fuel handling area exhaust unit, and control room ventilation unit surveillance testing include visual verification that the drain valves and drain piping have not experienced loss of material to the extent that their pressure boundary function is compromised. The procedures will include inspection of the external surfaces of ventilation drain valves and drain piping for any through-wall degradation (e.g., pinholes, etc.) or any general corrosion.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.37

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
27	The System Walkdown Program will be enhanced to include the attributes documented in LRA Section B.1.38, Page B-121, as clarified below. The following enhancements will be implemented in the System Walkdown Program prior to the period of extended operation to: • Ensure that balance of plant (BOP) systems are adequately addressed with regard to license renewal considerations. • Enhance the program description to emphasize management expectations that the entire system, where accessible, is walked down once a refueling cycle. • Enhance the program description to emphasize the accessibility of aspects of the system during refueling and maintenance outages. • Ensure that evidence of corrosion is monitored adequately. • Enhance the program description to emphasize the need to walkdown existing aging concerns, and to provide feedback to management regarding their condition (i.e., in system health reports or Corrective Action Program). If the condition declines significantly, initiate a condition report for further evaluation.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.38

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
	• the impact of non-safety related systems, structures, and components (SSCs) on safety related components with emphasis that preventive measures will be taken prior to loss of an SSC's license renewal intended function • extrapolation of conditions found in accessible structures/components to inaccessible structures/ components • ensuring that changes in material/environment combinations are addressed. Examples include; soil or water covering a pipe that was previously uncovered and excessive moisture in the area where previously not present • Develop and implement enhanced administrative controls.			
28	The Wall Thinning Monitoring Program is a new program that will be implemented prior to the period of extended operation. The Wall Thinning Monitoring Program inspections will be performed to ensure piping wall thickness is above the minimum required in order to avoid failures under normal conditions and postulated transient and accident conditions, including seismic events.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.39

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
29	The Water Chemistry Control – Primary and Secondary Water Chemistry Control Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.M2. The program will be enhanced to include the attributes documented in LRA Section B.1.40.1, Pages B-124 and B-125. The following enhancements to the Primary and Secondary Water Chemistry Control Program will be implemented prior to the period of extended operation: • Revise the program controlling procedures to require individual implementing procedures to identify and prescribe any special collection and preservation needs of a sample. • Bring the parameters monitored/inspected and acceptance criteria into clear alignment with the EPRI water chemistry guidelines. • Include sulfate monitoring criteria for the refueling water storage tank (RWST) that are consistent with the EPRI guidelines, and the sulfate criteria for other systems impacted by RWST chemistry.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.40.1

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
30	The Water Chemistry Control – Chemistry One-Time Inspection Program will be implemented and completed prior to the period of extended operation. Combinations of nondestructive examinations (including visual, ultrasonic, and surface techniques) will be performed by qualified personnel following procedures that are consistent with the Section XI of the ASME B&PV Code and 10 CFR 50, Appendix B. Followup of unacceptable inspection findings may include expansion of the inspection sample size and locations.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.1.41 *See also Item 39 for additional discussion related to this commitment.*

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
31	The Fatigue Monitoring Program will be consistent with, but include an exception to, the program described in NUREG-1801, July 2001, Section X.M1, as documented in LRA Section B.2.2, Page B-133. The program will be enhanced to include the attributes documented in LRA, Section B.2.2, Page B-134. The following enhancements to the Fatigue Monitoring Program will be implemented prior to the period of extended operation: I&M will perform one or more of the following prior to the period of extended operation for the pressurizer surge line: • Further refine the fatigue analysis to lower the pressurizer surge line cumulative usage factors to below 1.0. • Repair the affected locations. • Replace the affected locations. • Manage the effects of fatigue of the pressurizer surge line by an NRC-approved inspection program. • Review changes to ASME B&PV Code actions relating to environmental fatigue. Any refined analysis will use the methodology approved by the ASME Committee and the NRC.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	B.2.2 *See also Items 33, 34, and 35 for additional commitments related to the Fatigue Monitoring Program.*

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
32	Interim staff guidance (ISG) document, ISG-5, addresses fuse holders that are not part of a larger assembly, but support safety related and nonsafety related functions in which a failure of a fuse precludes a safety function from being accomplished. Fuse holders that meet these requirements will be evaluated before the beginning of the period of extended operation for possible aging effects. The fuses will either be replaced, modified to remove the aging effects, or a program will be implemented to manage the aging effects. The aging management program (if needed) for fuse holders will consider the aging stressors for the metallic clips.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML033070177 10/31/2003 Attachment 1	2.1.3

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
33	As a supplement to the Fatigue Monitoring Program enhancement committed to in LRA Section B.2.2, I&M will perform one or more of the following activities prior to the period of extended operation for the Class 1 charging and safety injection nozzles: (1) Perform a plant-specific fatigue analysis of the Class 1 charging and safety injection nozzles, which includes environmental effects, to ensure that cumulative usage factors are below 1.0. (2) Manage the effects of fatigue of the Class 1 charging and safety injection nozzles by an NRC-approved inspection program (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC). The inspections are expected to be able to detect cracking due to thermal fatigue prior to loss of function. Replacement or repair will then be implemented such that the intended function will be maintained for the period of extended operation. (3) Repair portions of the Class 1 charging and safety injection nozzles at the affected locations, as necessary to ensure the intended function will be maintained for the period of extended operation.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML042740439 09/21/2004 Attachment 2 RAI 4.3.3-1	B.2.2 and 4.3.3 *See also Item 31*

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
	(4) Replace portions of the Class 1 charging and safety injection nozzles at the affected locations, as necessary to ensure the intended function will be maintained for the period of extended operation. (5) Monitor ASME Code activities to use the environmental fatigue methodology approved by the ASME Code Committee and the NRC.			
34	I&M will review the piping loads on the remaining hot penetrations to establish the base loads for the fatigue exemption provisions of ASME Code, Section III, paragraph N-415.1. The penetrations will be grouped based on their duty cycle during normal operations, including inservice testing duty. The cycle loads and stresses will be added to the piping analysis loads as appropriate, and the resultant loads will be compared to the fatigue exemption provisions of ASME Code, Section III, paragraph N-415.1. Any penetration group that does not meet the exemption provisions will be analyzed for fatigue using the most limiting penetration to represent the group. This evaluation will be completed prior to entering the period of extended operation and will be projected to the end of the period of extended operation.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML041750561 6/16/04 Attachment 6 RAI 4.6.2-1	B.2.2 and 4.6.2

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
35	As an enhancement to the Fatigue Monitoring Program described in LRA Section B.2.2, I&M will perform one or more of the following activities prior to the period of extended operation for Class 1 portions of residual heat removal (RHR) piping: (1) A plant specific fatigue analysis of Class 1 portions of RHR piping, which includes environmental effects, will be performed to ensure that cumulative usage factors remain below 1.0. (2) Repair of the Class 1 portions of RHR piping at the affected locations. (3) Replacement of the Class 1 portions of RHR piping at the affected locations. (4) Manage the effects of fatigue of the Class 1 portions of RHR piping by an NRC-approved inspection program (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC). The inspections are expected to be able to detect cracking due to thermal fatigue prior to loss of function. Replacement or repair will then be implemented such that the intended function will be maintained for the period of extended operation. (5) Monitor ASME Code activities to use the environmental fatigue methodology approved by	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML041750561 06/16/2004 Attachment 6 RAI 4.3.3-1	B.2.2 and 4.3.3

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
36	I&M will submit the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program for NRC staff review and approval 3 years prior to the period of extended operation. The Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program will be consistent with the program described in NUREG-1801, July 2001, Section XI.M16, as documented in LRA Section B.1.27, Page B-92.	Unit 1: October 25, 2011 Unit 2: December 23, 2014	ML042960028 10/18/2004 Attachment 2 RAI B.1.27-2	B.1.27
37	The Preventive Maintenance (PM) Program will manage loss of material for the EDG exhaust silencer internals. Visual inspections of the EDG exhaust silencer internals will be performed before the period of extended operation as part of the PM Program. The frequency of future inspections will be based on the initial inspection results.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML042960028 10/18/2004 Attachment 2 RAI 2.3.3.8-6	B.1.25 and 2.3.3.8
38	An insulation resistance test method, such as time-domain reflectometry (TDR), will be continued through the period of extended operation as part of the Non-EQ Instrumentation Circuits Test Review Program. The test frequency of instrumentation cables that are in the scope of this program, but are disconnected during calibration, shall be determined by I&M based on engineering evaluation, but will not be less than once every 10 years.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML042960028 10/18/2004 Attachment 2 RAI 3.6-2	B.1.21 and 3.6

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
39	I&M will include the auxiliary steam system copper heater coils, cast iron strainer housings, and carbon steel traps exposed to an internal steam environment in the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41. I&M will include these 10 CFR 54.4(a)(2) components (i.e., components in the CONT, DRAIN, PASS, RMS, RWD, and SD systems that are subject to aging management review and may be pressurized and contain raw or untreated water) in the Water Chemistry Control – Chemistry One-Time Inspection Program. Loss of material from these components, if any, should progress slowly. The one-time inspection of these components will provide assurance that loss of material is occurring at a rate slow enough to ensure that the intended functions of the components will be maintained during the period of extended operation. This one-time inspection will be performed near the end of the current operating term. The visual inspections will identify indications of loss of material. If loss of material is identified, an evaluation will be performed to confirm that the rate is sufficiently slow and that loss of intended	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML042960028 10/18/2004 Attachment 2 RAI 3.3.2.1.11-1	B.1.41 and 3.3.2.1.11

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
	function will not occur during the period of extended operation. For material and environment combinations with no evidence of loss of material or with very gradual loss of material, no further actions will be taken. For material and environment combinations with loss of material rates such that loss of intended function could occur during the period of extended operation, corrective actions will be taken in accordance with the Corrective Action Program. Appropriate corrective actions may consist of component replacement or additional inspections for components with the material and environment combination in which the excessive loss of material is found.			
40	The frequency noted on Page 6-3 of WCAP-14070 for valve leakage is assumed to occur for each of the reactor years of operation for the plant. The cycles are assumed to be for 40 years of operation. Therefore, this frequency is time dependent and constitutes a time-limited aging analysis (TLAA). I&M will perform one or more of the following activities to address fatigue of the auxiliary spray line piping evaluated in WCAP-14070:	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML042960028 10/18/2004 Attachment 2 RAI 4.3.1-1	B.2.2 and 4.3.1

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
	(1) Perform a plant-specific fatigue reanalysis of the auxiliary spray line piping prior to entering the period of extended operation to ensure that cumulative usage factors are below 1.0. (2) Repair piping at the affected locations. (3) Replace piping at the affected locations. (4) Manage the effects of fatigue of the auxiliary spray line piping by an NRC-approved inspection program (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC). It is expected that the inspections will be able to detect cracking due to thermal fatigue prior to loss of function. Replacement or repair, if necessary, will then be implemented such that the intended function will be maintained for the period of extended operation.			
41	As an enhancement to the Service Water Reliability Program described in License Renewal Application Section B.1.29: I&M will enhance the Service Water System Reliability Program to manage loss of material due to selective leaching of susceptible materials by visual inspections and hardness testing or an equivalent physical test.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML050950435 03/24/2005 Attachment 2 RAI B.1.29-1	B.1.29

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE ADAMS Accession No. Document Date Attachment No. RAI No.	INFORMATION LRA Section No. Comments
42	In response to the ACRS License Renewal Subcommittee comment regarding scheduling of buried piping inspections, I&M commits to enhance the new Buried Piping Inspection Program to require performance of an inspection of a sample of buried piping included in the scope of this program within ten years after entering the period of extended operation, unless an opportunistic inspection of similar underground piping has occurred within this ten-year period. Before the end of the tenth year of extended operation, I&M will perform an engineering evaluation to determine if sufficient inspections have been conducted to draw a conclusion regarding the ability of the underground coatings to protect the underground piping from degradation. If not, I&M will conduct an inspection of a sample of buried piping to allow that conclusion to be reached.	Unit 1: October 25, 2014 Unit 2: December 23, 2017	ML050950435 03/24/2005 Attachment 2	B.1.6

APPENDIX B: CHRONOLOGY

This appendix contains a chronological listing of the routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and the Indiana Michigan Power Company (I&M), and other correspondence regarding the NRC staff's reviews of the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2 (under Docket Numbers 50-315 and 50-316) license renewal application (LRA).

October 27, 2003	In a letter (signed by P. Kuo), NRC informed I&M their partial fee waiver for the process improvements in safety reviews of the D.C. Cook Nuclear Plant, Units 1 and 2 license renewal application was granted. ML033460291
October 31, 2003	In a letter, AEP:NRC:3034, (signed by M. K. Nazar), I&M submitted its LRA for the Donald C. Cook Nuclear Plant, Units 1 and 2. ML033070177
November 4, 2003	In a letter (signed by P. Kuo), NRC informed I&M of the receipt of the LRA for CNP Units 1 and 2 and Johnny Eads will be the PM for safety review and Robert Schaaf will be PM for environmental review. ML033100447
December 4, 2003	In a letter (signed by P. Kuo), NRC informed I&M the LRA was accepted and sufficient for docketing and proposed review schedule. ML033381153
January 14, 2004	In a letter, AEP:NRC:4034, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML040290749
January 15, 2004	In a memorandum (signed by J. Eads), NRC summarized the September 26, 2003 meeting between the NRC staff and I&M regarding the revised review process and the LRA. ML040158428
January 15, 2004	In a memorandum (signed by J. Eads), NRC summarized the November 12, 2003 meeting between the NRC staff and I&M to discuss the LRA. ML040160457
March 3, 2004	In a letter (signed by J. Eads), NRC provided I&M a revised schedule for the conduct of review for CNP. ML040650264
April 23, 2004	In a letter, AEP:NRC:4034-02, (signed by M. K. Nazar), I&M provided supplemental information to NRC concerning AMP audits related to the staff's review of the LRA. ML041270484
May 6, 2004	In a letter (signed by J. Eads), NRC provided I&M requests for additional information concerning its review of the LRA. ML041280528
May 7, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041280509

May 7, 2004	In a letter, AEP:NRC:4034-01, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041390360
May 10, 2004	In a memorandum (signed by J. Rowley), NRC summarized the March 25 and 26, 2004 conference call between the NRC staff and I&M concerning draft RAIs concerning the LRA. ML041330551
May 10, 2004	In a memorandum (signed by J. Rowley), NRC summarized the March 31, 2004 meeting between the NRC staff and I&M concerning scoping and screening of structures and components used in developing the LRA. ML041310231
May 10, 2004	In a memorandum (signed by J. Rowley), NRC summarized the April 13, 2004 meeting between the NRC staff and I&M to discuss proposed responeses to draft RAIs related to the staff's review of the LRA. ML041310444
May 19, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041400073
May 20 2004	In a letter, AEP:NRC:4034-05, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041550038
May 26, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041480115
June 1, 2004	In a memorandum (signed by J. Rowley), NRC summarized the May 6, 2004 conference call between the NRC staff and I&M to concerning draft RAIs related to the staff's review of the LRA. ML041530472
June 8, 2004	In a letter, AEP:NRC:4034-06, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041680255
June 8, 2004	In a letter, AEP:NRC:4034-07, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041670523
June 16, 2004	In a letter, AEP:NRC:4034-08, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041750561
June 22, 2004	In an inspection report, "Donald C. Cook Nuclear Power Plant, Units 1 and 2, NRC License renewal Scoping/Screening Inspection Report No. 05000315/2004003(DRS); 05000316/2004003(DRS)," NRC summarized the examination of procedures and records regarding the process of scoping

	and screening plant equipment subject to an aging management review. ML041740121
June 29, 2004	In a memorandum (signed by J. Rowley), NRC summarized the May 12, 2004 conference call between the NRC staff and I&M to concerning draft RAIs related to the staff's review of the LRA. ML041810427
June 30, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041830088
June 30, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041840218
June 30, 2004	In a letter, AEP:NRC:4034-09, (signed by M. K. Nazar), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML041890378
July 2, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML041840194
July 26, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042110285
July 27, 2004	In a memorandum (signed by J. Rowley), NRC summarized the May 17 and 21, 2004 conference call between the NRC staff and I&M to concerning responses RAIs related to the staff's review of the LRA. ML042110275
July 28, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042100372
July 30, 2004	In a memorandum (signed by J. Rowley), NRC summarized the July 8, 2004 conference call between the NRC staff and I&M to concerning RAIs related to the staff's review of the LRA. ML042120480
August 11, 2004	In a letter, AEP:NRC:4034-10, (signed by Joseph N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML0424704100
August 11, 2004	In a letter, AEP:NRC:4034-11, (signed by Joseph N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML042470402
August 11, 2004	In a letter, AEP:NRC:4034-12, (signed by Joseph N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML042450600

August 19, 2004	In a letter, AEP:NRC:4034-13, (signed by Joseph N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML042390469
August 20, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042330355
August 23, 2004	In a memorandum (signed by J. Rowley), NRC summarized the July 29, 2004 conference call between the NRC staff and I&M to concerning RAIs related to the staff's review of the LRA. ML042370375
August 31, 2004	In a memorandum (signed by J. Rowley), NRC summarized the August 10, 2004 conference call between the NRC staff and I&M to concerning RAIs related to the staff's review of the LRA. ML042440671
September 2, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042470181
September 2, 2004	In a letter, AEP:NRC:4034-15, (signed by J. N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML042530551
September 3, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042470393
September 21, 2004	In a letter, AEP:NRC:4034-16, (signed by J. N. Jensen), I&M provided a supplemental responses to NRC concerning RAIs related to the staff's review of the LRA. ML042740439
September 22, 2004	In an audit report, "Audit and Review Report for Plant Aging Management Reviews and Programs - Donald C. Cook Nuclear Plants, Units 1 and 2," NRC summarized its audit and review on aging management review and programs associated with the CNP LRA. ML042880347
September 22, 2004	In a memorandum (signed by J. Rowley), NRC summarized the August 24, 2004 conference call between the NRC staff and I&M concerning follow-up items RAIs related to the staff's review of the LRA. ML042790273
September 22, 2004	In an audit trip report (signed by D. Thatcher), NRC summarized the scoping and screening methodology audit regarding the Indiana Michigan Power Company license renewal application for the Donald C. Cook Nuclear Plant, Units 1 and 2, dated October 21, 2003. ML042600599
September 23, 2004	In a memorandum (signed by J. Rowley), NRC summarized the September 7, 2004 conference call between the NRC staff and I&M concerning follow-up items to RAIs related to the staff's review of the LRA. ML042790484

September 24, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042710130
September 27, 2004	In an e-mail (from N. Haggerty to J. Rowley), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML050560138
September 29, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042730269
September 29, 2004	In a memorandum (signed by J. Rowley), NRC summarized the September 1, 2003 meeting between the NRC staff and I&M to discuss the LRA. ML042740562
October 1, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042750313
October 15, 2004	In a memorandum (signed by J. Rowley), NRC summarized the September 8, 2004 conference call between the NRC staff and I&M to discuss and clarify an RAI related to the staff's review of the LRA. ML042920161
October 15, 2004	In a memorandum (signed by J. Rowley), NRC summarized the September 16, 2004 conference call between the NRC staff and I&M to discuss and clarify an RAI related to the staff's review of the LRA. ML042920437
October 18, 2004	In a letter, AEP:NRC:4034-17, (signed by J. N. Jensen), I&M provided a response to NRC concerning RAIs related to the staff's review of the LRA. ML042960028
October 19, 2004	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML042930422
October 28, 2004	In a letter, AEP:NRC:4034-19, (signed by J. N. Jensen), I&M provided the annual update information. ML043090467
November 12, 2004	In a memorandum (signed by J. Rowley), NRC summarized the October 13, 2004 conference call between the NRC staff and I&M to discuss and clarify an RAI related to the staff's review of the LRA. ML043170667
November 18, 2004	In a letter, AEP:NRC:4034-20, (signed by J. N. Jensen), I&M provided the annual update information. ML042960028
November 26, 2004	In a memorandum (signed by J. Rowley), NRC summarized the October 27, 2004 conference call between the NRC staff and I&M to discuss and clarify RAIs related to the staff's review of the LRA. ML043360131

December 21, 2004	In a report, "Safety Evaluation Report with Open Items Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2," NRC documents its technical review of the CNP LRA. ML043570539
December 23, 2004	In a memorandum (signed by J. Rowley), NRC summarized the November 10, 2004 conference call between the NRC staff and I&M to discuss and clarify RAIs related to the staff's review of the LRA. ML043650004
January 10, 2005	In an inspection report, "Donald C. Cook Nuclear Power Plant, Units 1 and 2, NRC Aging Management Program Inspection Report No. 0500315/2004013(DRS); 05000316/2004013(DRS)," NRC summarized the examination of procedures and records regarding implementation of aging management programs to support license renewal. ML050100227
January 12, 2005	In a memorandum (signed by J. Rowley), NRC summarized the November 23, 2004 conference call between the NRC staff and I&M to discuss and clarify RAIs related to the staff's review of the LRA. ML050120443
January 12, 2005	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML050120254
January 21, 2005	In a letter, AEP:NRC:5034, (signed by J. N. Jensen), I&M provided the responses to Open and Confirmatory Items in the Safety Evaluation Report with Open Items related to the License Renewal of Donald C. Cook Nuclear Plant, Units 1 and 2. ML050330373
February 11, 2005	In a memorandum (signed by J. Rowley), NRC summarized the January 11, 2005 conference call between the NRC staff and I&M to discuss and clarify RAIs related to the staff's review of the LRA. ML050460139
February 17, 2005	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML050490312
February 25, 2005	In a letter (signed by J. Rowley), NRC provided I&M requests for additional information concerning its review of the LRA. ML050560152
March 2, 2005	In a letter, AEP:NRC:5034-01, (signed by D. P. Fadel), I&M provided comments on the Safety Evaluation Report with Open Items related to the License Renewal of Donald C. Cook Nuclear Plant, Units 1 and 2. ML050690328
March 10, 2005	In a memorandum (signed by J. Rowley), NRC summarized the March 1, 2005 conference call between the NRC staff and I&M concerning comments made by Advisory Committee on Reactor Safeguards during the subcommittee meeting on the CNP LRA. ML050690376

March 24, 2005	In a letter, AEP:NRC:5034-02, (signed by J. N. Jensen), I&M provided response to request for additional information and Advisory Committee on Reactor Safeguards license renewal subcommittee comment. ML050950435
May 29, 2005	In a report, "Safety Evaluation Report Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2," NRC documents its final technical review of the CNP LRA. ML051510015
June 28, 2005	In a memorandum (signed by J. Rowley), NRC summarized the June 22, 2005 conference call between the NRC staff and I&M to discuss and clarify issues related to the staff's review of the LRA. ML051800335
July 13, 2005	In a memorandum (signed by J. Rowley), NRC summarized the July 1, 2005 conference call between the NRC staff and I&M to discuss and clarify issues related to the staff's review of the LRA. ML051940523
July 18, 2005	In a letter (signed by G. Wallis), the Advisory Committee on Reactor Safeguards provided its conclusions and recommendations on the renewal of the operating license for Donald C. Cook Nuclear Plant, Units 1 and 2. ML052000080

APPENDIX C: REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Donald C. Cook Nuclear Plant, Units 1 and 2, Docket Numbers 50-315 and 50-316.

American Society of Mechanical Engineers (ASME)

ASME Code, Section III

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ASME Code, Section III, Subsection NC-3200

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ASME Code, Section VIII, Division 1; AWWA; or MSS

ASME Code, Sections VIII or III, Subsections NC or ND

ASME Code, Section XI

ASME Code, Section XI, Subsection IWL

ASME Code Appendix G to Section XI

ASME Code Case N-481

ASME Code Case N-588

ASME Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves, Section XI, Division 1,"

ANSI B31.1, Power Piping

American Society for Testing and Materials (ASTM)

ASTM E185-82, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels"

ASTM E-185, "Standard Practice for Conducting Surveillance Tests for Light Water Cooled Nuclear Power Vessels"

ASTM standard D 1796, Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure), 2002

ASTM standard D 2709, Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge, 2001

ASTM standard D 2276, Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling

ASTM Standard D 4057, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, 2000

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10 CFR 50.34a, Design Objectives for Equipment to Control Release of Radioactive Material In Effluents - Nuclear Power Reactors, US Nuclear Regulatory Commission

10 CFR 50.48, Fire Protection, US Nuclear Regulatory Commission

10 CFR 50.49, Environmental Qualification of Electric Equipment to Safety For Nuclear Power Plants, US Nuclear Regulatory Commission

10 CFR 50.55a, Codes and Standards, US Nuclear Regulatory Commission

10 CFR 50.59, Changes, Tests, and Experiments, US Nuclear Regulatory Commission

10 CFR 50.61, Fracture Toughness Requirement For Protection Against Pressurized Thermal Shock Events, US Nuclear Regulatory Commission

10 CFR 50.62, Requirements For Reduction of Risk From Anticipated Transients Without Scram (ATWS) Events For Light-Water-Cooled Nuclear Power Plants, US Nuclear Regulatory Commission

10 CFR 50.63, Loss of All Alternating Current Power, US Nuclear Regulatory Commission

10 CFR 50.67, Accident Source Term, US Nuclear Regulatory Commission

10 CFR 50 Appendix J, Primary Reactor Containment Leakage Testing For Water-Cooled Power Plants, US Nuclear Regulatory Commission

10 CFR 54.21, Contents of Application—Technical Information, US Nuclear Regulatory Commission

10 CFR Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, US Nuclear Regulatory Commission

10 CFR 54.4, Scope, US Nuclear Regulatory Commission

10 CFR 54.30, Matters Not Subject To A Renewal Review, US Nuclear Regulatory Commission

10 CFR 100.11, Determination of Exclusion Area, Low Population Zone, and Population Center Distance, US Nuclear Regulatory Commission

29 CFR Chapter XVII, 1910.134, Respiratory Protection, US Nuclear Regulatory Commission

29 CFR Chapter XVII, 1926.134, Respiratory Protection, US Nuclear Regulatory Commission

42 CFR Chapter I, Part 84, Approval of Respiratory Protective Devices, US Nuclear Regulatory Commission

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EPRI NP-1406-SR, "Nondestructive Examination Acceptance Standards."

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EPRI NP-5569, Chromate Substitutes for Corrosion Inhibitors in Cooling Systems, December 1987

EPRI NP-5769, Degradation and Failure of Bolting in Nuclear Power Plants, Volumes 1 and 2, May 1988

EPRI TR-105714, PWR Primary Water Chemistry Guidelines: Vol. 1: Revision 4; Vol. 2: Revision 4 Volume 2, January 1999

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NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors," May 28, 2004

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NRC Order EA-03-009, ISSUANCE OF ORDER ESTABLISHING INTERIM INSPECTION REQUIREMENTS FOR REACTOR PRESSURE VESSEL HEADS AT PRESSURIZED WATER REACTORS

Generic Safety Issue
GSI-166, Adequacy of the Fatigue Life of Metal Components

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NRC Generic Letter (GL) 88-05, "Boric Acid Corrosion Of Carbon Steel Reactor Pressure Boundary Component in PWR Plants," March 17, 1988

NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," July 18, 1989

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NRC 2004-01 Regarding Inspection of Alloy 82/182/600 Materials Used in Pressurizer Penetrations and Steam Space Piping Components (July 27, 2004)

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NUREG-1766, Section 2.1.3.1, "Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and Surry Power Station Station, Units 1 and 2," December 2002

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"PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds,"

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WCAP-15973-P, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs"

APPENDIX D: PRINCIPAL CONTRIBUTORS

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NRC FORM 335 (9-2004) NRCMD 3.7 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-1831
2. TITLE AND SUBTITLE Safety Evaluation Report Related to the License Renewal of the Donald C. Cook Nuclear Plant, Units 1 and 2	3. DATE REPORT PUBLISHED MONTH: July YEAR: 2005 4. FIN OR GRANT NUMBER
5. AUTHOR(S) Jonathan G. Rowley	6. TYPE OF REPORT 7. PERIOD COVERED *(Inclusive Dates)* 10/31/2003 - 05/29/2005

8. PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)*

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-001

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 item number 8 above

10. SUPPLEMENTARY NOTES

Docket No. 50-315 and No. 50-316

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Donald C. Cook Nuclear Plant (CNP), Units 1 and 2, license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated October 31, 2003, Indiana Michigan Power Company (the applicant) submitted the LRA for CNP in accordance with Title 10, Part54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the Code of Federal Regulations (10 CFR Part 54 or the Rule). The applicant is requesting renewal of the operating license for CNP Unit 1(LicenseNo. DRP-58) and CNP Unit 2(LicenseNo. DRP-74) for a period of 20 years beyond the current license expirations of midnight, October25, 2014 and December 23, 2017, respectively.

The CNP is located along the eastern shore of Lake Michigan in Lake Charter Township, Berrien County, Michigan; approximately 11 miles south southwest of Benton Harbor, Michigan. The nearest town is Bridgman, Michigan, which is approximately 2 miles south of the plant site. Each unit employs a pressurized water reactor (PWR) nuclear steam supply system (NSSS) furnished by Westinghouse Electric Corporation. The Unit 1 reactor is licensed for a power output of 3304 megawatts-thermal (MWt), and the Unit 2 reactor is licensed for a power output of 3468 MWt. The approximate net electrical outputs of Unit 1 and Unit 2 are 1080 megawatts-electric (MWe) and 1155 MWe, respectively.

The staff reviewed the CNP 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. The staff's conclusion of its review of the CNP 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.)*	13. AVAILABILITY STATEMENT
10 CFR Part 54, license renewal application, Donald C. Cook Nuclear Power Plant, scoping, screening, aging management, time-limited aging analysis, safety evaluation report, Docket No. 50-315, Docket No. 50-316, operating license number DPR-58, operating license number DPR-74, Indiana Michigan Power Company	unlimited
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