NUREG-1843

Safety Evaluation Report
Related to the License Renewal of the Browns Ferry Nuclear Plant, Units 1, 2, and 3

Docket Nos. 50-259, 50-260, and 50-296

Tennessee Valley Authority

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

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Browns Ferry Nuclear Plant (BFN), Units 1, 2, and 3, license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). By letter dated December 31, 2003, Tennessee Valley Authority (TVA or the applicant) submitted the LRA for BFN in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54). TVA is requesting renewal of the operating licenses for BFN Units 1, 2, and 3, (Facility Operating License Numbers DPR-33, DPR-52, and DPR-68, respectively) for a period of 20 years beyond the current expiration dates of midnight December 20, 2013, for Unit 1; midnight June 28, 2014, for Unit 2; and midnight July 2, 2016, for Unit 3.

The BFN units are located on the north shore of Wheeler Reservoir in Limestone County, Alabama, at Tennessee River Mile 294. The site is approximately 30 miles west of Huntsville, Alabama; it is also 10 miles northwest of Decatur, Alabama and 10 miles southwest of Athens, Alabama. The NRC issued the construction permits for Units 1 and 2 on May 10, 1967; for Unit 3 on July 31, 1968. The NRC issued the operating licenses for Unit 1 on December 20, 1973; for Unit 2 on June 28, 1974; and for Unit 3 on July 2, 1976. All of the units consist of a Mark I boiling water reactor (BWR) with a nuclear steam supply system supplied by General Electric Corporation. The balance of each of the plants was originally designed and constructed by the Tennessee Valley Authority. Unit 1 licensed power output is 3293 megawatt thermal (MWt), with a gross electrical output of approximately 1100 megawatt electric (MWe). Units 2 and 3 licensed power output is 3458 MWt, with a gross electrical output of approximately 1155 MWe. The units operated from the original licensing until 1985 when they were voluntarily shut down by the applicant to address management and technical issues. The applicant then implemented a comprehensive nuclear performance plan to correct the deficiencies that led to the shutdown. This plan included changes in management, programs, processes and procedures, as well as extensive equipment refurbishment, replacement, and modifications. Unit 2 was subsequently restarted in 1991, and Unit 3 followed in 1995. In the early 1990s, the applicant decided to defer restart of Unit 1. Unit 1 is currently in a shutdown status.

This SER presents the status of the staff's review of information submitted to the NRC through December 31, 2005, the cutoff date for consideration in the SER. The staff identified open items and confirmatory items that had to be resolved before the staff could make a final determination on the application. SER Sections 1.5 and 1.6 summarize these items and their resolutions. Section 6 provides the staff’s final conclusion on the review of the BFN LRA.

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ABBREVIATIONS

AC	alternating current
ACI	American Concrete Institute
ACSR	aluminum conductor steel reinforced
ACRS	Advisory Committee on Reactor Safeguards
ADHR	auxiliary decay heat removal
ADS	atmospheric dilution system
AERM	aging effect requiring management
AFFF	aqueous film-forming foam
AFW	auxiliary feedwater
AHC	access hole cover
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
ANSI	American National Standards Institute
APCSB	Auxiliary and Power Conversion Systems Branch
APRM	average power range monitor
URI	unresolved issue
ART	adjusted reference temperature
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
AST	alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	boiler and pressure vessel
B&W	Babcock and Wilcox
BFN	Browns Ferry Nuclear Plant
BWR	boiling water reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAD	containment atmosphere dilution
CASS	cast austentitic stainless steel
CBF	cycle-based fatigue
CCCW	closed-cycle cooling water
CCWP	condensate circulating water pump
CF	chemistry factor
CFR	*Code of Federal Regulations*
CI	confirmatory item
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CO_2	carbon dioxide
CRD	control rod drive
CS	core spray
CUF	cumulative usage factor

CVP	Cleanliness Verification Program
CWST	condensate water storage tank
DBA	design-basis accident
DBE	design-basis event
DC	design of civil structures
DCN	design change notice
DG	diesel generator or Draft Regulatory Guide
DGB	diesel generator building
dpa	displacements per atom
ECCS	emergency core cooling system
ECP	electrochemical potential
EDG	emergency diesel generator
EECW	emergency equipment cooling water
EFPY	effective full-power year
EMA	equivalent margin analysis
EMPAC	enterprise maintenance planning and control
EOL	end of life
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
EVT	enhanced visual test
FAC	flow-accelerated corrosion
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FP	fire protection
FPC	fuel pool cooling and cleanup
FPR	Fire Protection Report
FSAR	final safety analysis report
FW	feedwater
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria
GE	General Electric Corporation
GEIS	Generic Environmental Impact Statement
GENE	General Electric Nuclear Energy
GES	general engineering specification
GL	generic letter
GSI	generic safety issue
HELB	high-energy line break
HEPA	high efficiency particulate air
HH	handhole
HPCI	high pressure coolant injection
HPFP	high pressure fire protection
HSLA	high-strength low-alloy

HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry
HX	heat exchanger
I&C	instrumentation and control
IASCC	irradiation assisted stress corrosion cracking
ID	inside diameter
IGSCC	intergranular stress corrosion cracking
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IPS	intake pumping station
IR	insulation resistance
IRM	intermediate range monitor
ISG	interim staff guidance
ISI	inservice inspection
ISP	Integrated Surveillance Program
kV	kiloVolt
LER	Licensee Event Report
LLRT	local leak rate test
LLRW	low level radioactive waste
LOCA	loss-of-coolant-accident
LP	layup program
LPCI	low pressure coolant injection
LPRM	local power range monitor
LR	license renewal
LRA	license renewal application
LTOP	low temperature over-pressure
LWR	light water reactor
MEAP	material, environment, aging effects, and aging management program
MEL	master equipment list
MeV	million electron Volts
MIC	microbiologically influenced corrosion
MS	main steam
MSIV	main steam isolation valve
MWe	megawatt electric
MWt	megawatt thermal
n/cm^2	neutrons per square centimeter
NDE	nondestructive examination
NEDP	Nuclear Engineering Design Procedure
NEI	Nuclear Energy Institute
NEIL	Nuclear Electric Insurance Limited
NEPA	National Environmental Policy Act of 1969
NFPA	National Fire Protection Association
NMCA	noble metal chemical application

NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSR	non-safety-related
NSSS	nuclear steam supply system
NUREG	U.S. Nuclear Regulatory Commission Regulatory Guide
O_2	oxygen
OCCW	open-cycle cooling water
OE	operating experience
OFS	orificed fuel supports
OI	open item
PB	pressure boundary
PER	Problem Evaluation Report
PFM	probabilistic fracture mechanics
PT	penetrant testing
PTS	pressurized thermal shock
PUAR	Plant Unique Analysis Report
PVC	polyvinyl chloride
PW	pipe whip restraint
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
RAI	request for additional information
RBCCW	reactor building closed cooling water
RBM	rod block monitor
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCW	raw cooling water
RG	regulatory guide
RH	relative humidity
RHR	residual heat removal
RHRSW	residual heat removal service water
RPV	reactor pressure vessel
RPVII	reactor pressure vessel internals inspection
RSW	raw service water
RT	reference temperature
RT_{NDT}	reference temperature nil ductility transition
RV	reactor vessel
RVI	reactor vessel internal
RWCU	reactor water cleanup
SBF	stress-based fatigue
SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking

SCV	steel containment vessel
SER	Safety Evaluation Report
SGT	standby gas treatment
SI	surveillance instruction
SIL	Service Information Letter
SLC	standby liquid control
SMP	Structures Monitoring Program
SO_2	sulfur dioxide
SOC	statement of consideration
SOER	Significant Operating Experience Report
SP	shelter/protection
SPP	standard program and process
SR	safety-related
SRM	source range monitor
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SRV	safety relief valve
SS	stainless steel or structural support or systems and structures
SSA	safe shutdown analysis
SSC	system, structure, and component
SSE	safe shutdown earthquake
TI	technical instruction
TIP	traversing in-core probe
TLAA	time-limited aging analysis
TS	technical specification
TVA	Tennessee Valley Authority
TVAN	Tennessee Valley Authority Nuclear
UFSAR	updated final safety analysis report
UNID	unique component identifier
USAS	USA standard
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultra violet
V	volt
VFLD	vessel flange leak detection
VIP	vessel and internals project
WO	work order
XLPE	cross-linked polyethylene

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SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal (LR) for the Browns Ferry Nuclear Plant (BFN), as filed by Tennessee Valley Authority (TVA or the applicant). By letter dated December 31, 2003, TVA submitted its application to the U.S. Nuclear Regulatory Commission (NRC or the Commission) for renewal of the BFN operating licenses for an additional 20 years. The NRC staff (the staff) prepared this report, which summarizes the results of its safety review of the renewal application for compliance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations*, (10 CFR Part 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.” The NRC license renewal project managers for the BFN license renewal review are Ram Subbaratnam and Yoira Diaz-Sanabria. Mr. Subbaratnam can be contacted by telephone at 301-415-1478 or by electronic mail at rxs2@nrc.gov; Ms. Diaz-Sanabria can be contacted by telephone at 301-415-1594 or by electronic mail at yks@nrc.gov. Alternatively, written correspondence may be sent to the following address:

License Renewal and Environmental Impacts Program
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Attention: Ram Subbaratnam, or Yoira Diaz-Sanabria, Mail Stop 0-11-F1

In its December 31, 2003, submittal letter, the applicant requested renewal of the operating licenses issued under Section 104b (Operating License Nos. DPR-33, DPR-52, and DPR-68) of the Atomic Energy Act of 1954, as amended, for BFN Units 1, 2, and 3 for a period of 20 years beyond the current license expiration dates of midnight December 20, 2013, for Unit 1; midnight June 28, 2014, for Unit 2; and midnight July 2, 2016 for Unit 3. The BFN units are located on the north shore of Wheeler Reservoir in Limestone County, Alabama, at Tennessee River Mile 294. The site is approximately 30 miles west of Huntsville, Alabama; it is also 10 miles northwest of Decatur, Alabama and 10 miles southwest of Athens, Alabama. The NRC issued the construction permits for Unit 1 on May 10, 1967; for Unit 2 on May 10, 1967; and for Unit 3 on July 31, 1968. The staff issued the operating licenses for Unit 1 on December 20, 1973; for Unit 2 on June 28, 1974; and for Unit 3 on July 2, 1976. All of the units consist of a Mark I boiling water reactor (BWR) with a nuclear steam supply system supplied by General Electric Corporation. The balance of each of the plants was originally designed and constructed by TVA. Unit 1 licensed power output is 3293 megawatt thermal (MWt), with a gross electrical output of approximately 1100 megawatt electric (MWe). Units 2 and 3 licensed power output is 3458 MWt, with a gross electrical output of approximately 1155 MWe. The updated final safety analysis report (UFSAR) contains details concerning the plant and the site. The units operated from the original licensing until 1985 when they were voluntarily shut down by the applicant to address management and technical issues. The applicant then implemented a comprehensive nuclear performance plan to correct the deficiencies that led to the shutdown. This plan included changes in management, programs, processes and procedures, as well as extensive equipment refurbishment, replacement, and modifications. Unit 2 was subsequently restarted in

1991, and Unit 3 followed in 1995. In the early 1990s, the applicant decided to defer restart of Unit 1. Unit 1 is currently in a shutdown status.

The license renewal process consists of two concurrent reviews - a technical review of safety issues and an environmental review. The NRC regulations found in 10 CFR Parts 54 and 51, respectively, set forth the requirements against which license renewal applications are reviewed. The safety review for the BFN license renewal is based on the applicant's license renewal application (LRA) and on the responses to the staff's requests for additional information (RAIs). The applicant supplemented and clarified its responses to the LRA and RAIs in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through December 31, 2005. The public may view the LRA and all pertinent information and materials, including the UFSAR mentioned above, at the NRC Public Document Room, located in One White Flint North, 11555 Rockville Pike (first floor), Rockville, MD 20852-2738 (301-415-4737/800-397-4209), and at the Athens-Limestone Public Library, 405 South Street East, Athens, AL, 35611. In addition, the public may find the BFN Units 1, 2, and 3 LRA, as well as materials related to the license renewal review, on the NRC website at www.nrc.gov.

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

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

SER Appendix A is a table that identifies the applicant's commitments associated with the renewal of the operating licenses. Appendix B provides a chronology of the principal correspondence between the NRC and the applicant related to the review of the application. Appendix C is a list of principal contributors to the SER. Appendix D is a bibliography of the references used in support of the review.

In accordance with 10 CFR Part 51, the staff prepared a plant-specific supplement to the Generic Environmental Impact Statement (GEIS). This supplement discusses the environmental considerations related to renewing the licenses for BFN Units 1, 2, and 3. The staff issued (draft) Supplement 21 to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Browns Ferry Nuclear Plant, Units 1, 2, and 3: Draft Report for Comment,” on December 3, 2004. The final report was issued on June 23, 2005.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations, rather than on 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 staff anticipated interest in license renewal and held a workshop on nuclear power plant aging. This workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. On the basis of the results 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 staff 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 staff published the license renewal rule in 10 CFR Part 54 (the Rule). The staff participated in an industry-sponsored demonstration program to apply the Rule to a pilot plant and to gain experience necessary to develop 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 staff found that adverse effects of aging occur to plant systems and components and the effects are managed during the period of initial license. In addition, the staff 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 staff 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 staff 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 staff initiated these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the revised Rule clarified and simplified the integrated plant assessment (IPA) process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the staff pursued a separate rulemaking effort and developed an amendment to 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal and fulfill 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 SSCs, as well as a few other safety-related (SR) issues, 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 as including those SSCs (1) that are SR; (2) whose failure could affect SR 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 (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license must review all SSCs that are within the scope of the Rule to identify SCs that are subject to an aging management review (AMR). Those SCs that are subject to an AMR perform an intended function without moving parts or without a change in configuration or properties, and 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 the effects of aging will be managed 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; however, active equipment is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may affect active equipment are more readily detectable and can be identified and corrected through routine surveillance, performance monitoring, and maintenance activities. The surveillance and maintenance activities 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), each LRA is required to include a supplement to the FSAR (final safety analysis report) or UFSAR. This supplement must contain a summary description of the applicant’s programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

License renewal also requires the identification and updating of the TLAAs. During the design phase for a plant, certain assumptions are made about the length of time the plant can 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 the effects of aging on these SSCs can be adequately managed for the period of extended operation.

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

In the LRA, BFN fully utilizes the process defined in NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” issued in 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 time, effort, and resources used to review an applicant's LRA can be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry. The report also serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff determined can provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

Title 10, Part 51, of the *Code of Federal Regulations* (10 CFR Part 51) governs environmental protection regulations. In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared a "Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants" (NUREG-1437, Revision 1) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are codified in Appendix B to Subpart A of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of those environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether new and significant information existed that the GEIS did not consider. As part of its scoping process, the staff held a public meeting on April 1, 2004, in Athens, Alabama to identify environmental issues specific to the plant. The NRC's draft plant-specific Supplement 21 to the BFN GEIS, which was issued on December 1, 2004, documents the results of the environmental review and includes a preliminary recommendation with respect to the license renewal action. The staff held another public meeting on January 25, 2005, in Athens, Alabama, to discuss the draft plant-specific Supplement 21 to the GEIS. After considering comments on the draft, the staff published a final, plant-specific supplement to the GEIS separately from this report on June 23, 2005.

1.3 Principal Review Matters

1.3.1 Operating Experience for BFN Unit 1 in Satisfying the Intent of the License Renewal Rule

1.3.1.1 Regulatory Framework

Section 54.17(c) of 10 CFR states that an application for a renewed license may not be submitted earlier than 20 years before the expiration of the operating license currently in effect. The operating license for BFN Unit 1 expires on December 20, 2013; for Unit 2, on June 28, 2014; and for Unit 3, on July 2, 2016. The license renewal application for Units 1, 2, and 3 was submitted on December 31, 2003. Thus, all units met this regulatory requirement and no plant-specific exemptions were required.

When 10 CFR Part 54 was published, the Commission originally determined that a 20-year period of plant-specific operating experience would allow adequate assessment of any age-related degradation of plant structures, systems, and components. The statement of consideration (SOC) hence implied an intent of a 20-year threshold limit to ensure that substantial operating experience is accumulated by licensees before the submittal of license renewal applications. From that consideration, BFN Unit 1's 10-year operating history does not entirely meet that intent. The Advisory Committee on Reactor Safeguards (ACRS or the Committee), in an interim report dated October 19, 2005, on the safety aspects of the license renewal application for BFN Units 1, 2, and 3, commented that 10 years of plant-specific operating experience for BFN Unit 1, by itself, does not fully meet the intent of the license renewal rule. TVA, in its response dated November 16, 2005, submitted for the Committee's consideration the following information in support of its claim that Unit 1 meets the intent of the Rule.

1.3.1.2 Collective Operating Experience of the Three BFN Units

BFN Unit 1 was licensed and began initial operation in 1973. Unit 2 began operation in 1974. Units 1 and 2 operated until March 22, 1975, at which time both units were shut down due to a fire in the Unit 1 reactor building. Units 1 and 2 resumed operation in 1976, and Unit 3 began initial operation in 1977. All three units were operated until March 1985, at which time the applicant voluntarily shut them down to address regulatory and management issues.

Following successful resolution of the management issues and the Unit 2 and common regulatory issues, Unit 2 was restarted on May 23, 1991. Unit 3 remained in a layup/recovery mode for approximately 10 years and, following resolution of the Unit 3 regulatory issues, Unit 3 was restarted on November 19, 1995. Both Units 2 and 3 have operated with high capacity factors into the present time. In the early 1990s, the applicant decided to defer the restart of Unit 1.

On May 16, 2002, the applicant announced the Unit 1 Restart Project. As part of the restart project, the applicant is performing the same restart programs and implementing the same modifications that were previously completed on Units 2 and 3. At restart, Unit 1 will be operationally the same as Units 2 and 3. Based only on the periods of operation as of 2005, Unit 1 has operated for approximately 10 calendar years, Unit 2 has operated for approximately 23 calendar years and Unit 3 has operated for approximately 18 calendar years.

All three BFN units share common facilities, materials, and environments. The three units are identical General Electric BWR 4 reactors with Mark I containments. TVA designed and constructed the units to be materially and operationally identical, with identical systems, components, materials, and environments. For a given power level, the system process conditions (e.g., pressure, temperatures, moisture content, chemical properties, flow rates, velocities, etc.) are identical. There is one UFSAR for the three units. Operating procedures and Technical Specifications are nearly identical. Due to outage scheduling, small unit differences may exist for short periods of time but are eliminated as modifications are installed on other units during subsequent unit outages. Thus, over 51 years of operating experience is accumulated collectively by the three units and this collective experience has been used to support the preparation of the three-unit license renewal application. Addressing stakeholders' questions when the Rule was published in 1991, the SOC states that the licensees and the

NRC can substitute nuclear industry operating experience for plant-specific experience, and the staff need not limit its safety finding to information developed solely from plant-specific experience of an applicant. Therefore, the collective 51 years experience is sufficient to support the renewal of the BFN Unit 1 operating license, because the Unit 2 operating experience, along with the experience during the ten-year extended layup and subsequent operation of BFN Unit 3, applies to Unit 1. Specifically, in pursuing license renewal for BFN Unit 1, TVA has relied not only on Unit 1's CLB, including the specific changes in Appendix F of the LRA, but also on Unit 1's plant-specific operating experience, the operating experience gained from BFN Units 2 and 3, and relevant industry-wide operating experience. This experience base satisfies and is consistent with the regulatory requirements and intent of 10 CFR 54.17(c).

1.3.1.3 Corrective Action Program (CAP) Applicability

In its submittal dated January 31, 2005, TVA stated that the three BFN units are essentially identical, and the application is not unit-specific regarding aging management programs. The changes being implemented as part of Unit 1 restart activities are consistent with the changes made previously to Units 2 and 3. AMPs are common for all three units based on their CLB. Since at restart the Unit 1 licensing basis will be consistent with that of Units 2 and 3, the aging management programs specified will be applicable to all three units. In addition to the similarities between the Units 2 and 3 and Unit 1 licensing and design bases, specific programs function such that relevant Units 2 and 3 operating experience is passed on to Unit 1. First, the Corrective Action Program (CAP) applies to all TVA organizations involved in nuclear power activities. This program is not unit specific and, as applicable, a condition identified at any BFN unit is reviewed for generic implications potentially applicable to the other units. TVA also has an administrative procedure for the review and dissemination of operating experience obtained from both external and internal sources. This procedure requires screening of such information for potential BFN applicability. This information is received from sources such as NRC Information Notices, Institute of Nuclear Power Operations (INPO), nuclear steam supply system (NSSS) vendor reports/notices, and in-house operating experience. If an item is determined to be applicable to BFN, then the information is addressed in the CAP. Thus, these programs help ensure that relevant operating experience (OE) is applied to all three units.

1.3.1.4 Aging Mechanism Similarities Between Units after Layup and Recovery

During the collective periods of BFN operation, including recovery, the three units have experienced similar aging mechanisms. For example, each unit has experienced the expected wear such as Flow Accelerated Corrosion (FAC), general corrosion, and microbiologically induced corrosion (MIC). Applicable aging mechanisms for the passive plant features are identified in LRA Section 3.0. The aging mechanisms for the passive plant features are well known and are addressed by existing plant programs and procedures.

Since components and structures within the scope of AMRs for the three units contain the same materials and have experienced the same process conditions, all three units experience similar aging effects. Unit 1 has been shut down since 1985. During the shutdown period, it experienced aging effects analogous to those experienced on Units 2 and 3 during their shutdown periods. In this regard, the applicant has utilized the OE gained from restarting and operating Units 2 and 3, in recovering Unit 1, and has undertaken proactive steps to use the aging mechanisms experienced during subsequent operation of Units 2 and 3 to determine the necessary modifications to Unit 1 to preclude aging effects when possible. In many cases, the aging mechanisms such as FAC had not resulted in significant wear in Unit 1; however, the recovery effort has replaced the FAC-susceptible material with FAC-resistant material. The Unit 1 locations for replacements were expanded to address additional locations with geometry/process conditions similar to Units 2 and 3 wear locations even if Units 2 and 3 had not experienced significant wear in all similar locations. For example, if Unit 2 had experienced wear at one elbow, but not at two other elbows of similar material/geometry/process conditions, the Unit 1 restart scope included all 3 locations. The Unit 1 recovery design changes have not resulted in the installation of types of material different from those present in Units 2 and 3. Thus, during the collective periods of BFN operation, including recovery, the three units have experienced similar aging mechanisms and will be appropriately managed during the period of extended operations.

1.3.1.5 Plant Upgrades

As part of the recovery of Units 2 and 3, TVA implemented various plant upgrades (i.e., design changes) in response to regulatory issues and/or to improve plant operating characteristics. This upgrade experience has been brought to bear in the Unit 1 recovery effort. For example, as part of the recovery of Units 2 and 3, TVA replaced piping that was susceptible to intergranular stress corrosion cracking (IGSCC). Similar design changes are being installed on Unit 1 as part of the recovery process. IGSCC-susceptible piping in the reactor recirculation, residual heat removal (RHR), reactor water cleanup (RWCU), and core spray (CS) systems on Unit 1 is being replaced using materials that are resistant to IGSCC. (Also, see the beginning of SER Section 3.7)

The applicant stated that it has effectively managed aging through various programs and has replaced and upgraded the plant to manage the effects of aging. For example, the systems susceptible to FAC are monitored in accordance with EPRI guidelines (LRA Section B.2.1.15, SER Section 3.0.3.2.9). Piping on Units 2 and 3 is monitored for FAC-induced wear and replaced as needed. In many cases, the piping has been replaced with FAC-resistant chrome molybdenum piping (LRA Section B.2.1.15, SER Section 3.0.3.2.9). Reactor vessel components such as the shroud, vessel welds, jet pumps, core plate, and top guide are inspected by accepted industry standards such as the Boiling Water Reactor Vessel Internals Program (BWRVIP) and repairs/replacements performed as required (LRA Section B.2.1.12, SER Section 3.0.3.2.7). Raw water piping that is used to transfer heat from SR systems to the ultimate heat sink is managed by the Open Cycle Cooling Water System Program (LRA Section B.2.1.17, SER Section 3.0.3.2.11). The primary containment liner is inspected in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWE for steel containments (Class MC) requirements (LRA Section B.2.1.31, SER Section 3.0.3.1.9). As explained in the LRA, these same programs are used on all three units.

1.3.1.6 Inspections/Programs Expanded to Proactively Prevent Age Related Wear

In its submittal dated November 16, 2005, TVA stated that the Unit 1 inspections/programs for other aging mechanisms have been expanded to proactively prevent age-related wear. The scope of replacement of IGSCC-susceptible piping is significantly larger in Unit 1 than in Units 2 or 3; thus, Unit 1 will contain a significantly larger scope of new pipe that has no pre-existing aging effects. Since similar materials and geometry were used in Unit 1 for the expanded scope, there were no new aging mechanisms introduced. In addition, the Unit 1 systems that perform a required function in the defueled condition, or that directly support the operation of Unit 2 or Unit 3, have been continuously operated and maintained under applicable Technical Specifications and plant programs since shutdown in 1985. This OE has been factored into the LRA. Examples of these piping systems include portions of fuel pool cooling and cleanup (FPC), control rod drive (CRD), raw cooling water (RCW), reactor building closed cooling water (RBCCW), RHR, residual heat removal service water (RHRSW), EECW, and control air systems.

The applicant has maintained the Unit 1 systems in a physical condition during shutdown similar to those of Units 2 and 3 during their shutdown periods. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as those found in the operating units. These systems have experienced the same aging mechanisms and rates as experienced by the similar Units 2 and 3 systems for shutdown conditions. The Units 1, 2, and 3 reactor buildings are one continuous structure, and the external operating environments of the systems are the same. Even though Unit 1 was in an extended outage, the overall environmental conditions affecting external surfaces in Unit 1 were maintained consistent with those of Units 2 and 3. Unit 1 had the normal ventilation systems in service, and equipment was maintained to prevent system leakage so that the equipment was not subjected to aggressive external conditions.

Other Unit 1 systems have been in a layup condition, and this prior layup experience has been applied to Unit 1 license renewal. For example, Unit 1 was placed in layup using the same philosophy, processes, and conditions as used for Unit 3. Some piping systems (or portions of piping systems) were placed into a "wet layup" under TVA's Unit 1 layup procedure, which include RV, RCS, RWCU, portions of RHR, CS, and feedwater (FW) systems. The water chemistry within these Unit 1 piping systems was monitored for compliance with the water quality requirements. Thus, it would not be expected that a different aging mechanism or rate would exist in wet layup compared to what would have occurred if the systems were in normal operation. The full scope of BWRVIP inspections have been performed on the Unit 1 reactor vessel as part of the restart project. No adverse effects from the layup period were found, and repairs/ replacements not related to layup will be performed as required. The reactor water recirculation system and reactor water cleanup system piping, both large bore and small bore, have been replaced. The RHR and CS piping that was in wet layup has also been replaced. The piping was replaced with the same materials that were used in Units 2 and 3. Ultrasonic inspections of the FW piping have confirmed that the piping does not exhibit adverse effects from the wet layup period. Thus, extensive layup experience has been applied to the Unit 1 license renewal.

Some Unit 1 piping systems (or portions of piping systems) were drained and placed in dry layup, which included reactor core isolation cooling (RCIC), high pressure coolant injection (HPCI), main steam (MS), RHR, CS, and FW systems. The exterior of the system/component was maintained at nominal reactor or turbine buildings ambient conditions, which would have been the same in Units 1, 2, and 3. Thus, the dry layup systems would have experienced aging at a rate less than or equal to that of the corresponding Unit 2/3 system.

Some Unit 1 systems were simply drained with no controlled environment. As a result, portions of two Unit 1 systems experienced accelerated aging. The accelerated aging of these systems was previously identified as part of the OE from the Unit 3 outage between 1985 and 1995. These were portions of the Unit 1 RHRSW piping inside the reactor building and some small bore raw cooling water piping. As explained in the beginning of SER Section 3.7, Units 2 and 3 OE was incorporated into Unit 1 aging management activities.

As stated previously, all units met the regulatory requirement and no plant-specific exemptions were required per 10 CFR 54.17(c). However, the staff questioned the applicant’s statement of the operating experience applicability from Units 2 and 3 to Unit 1 and are not entirely satisfied that Unit 1 operating experience meets the intent of the Rule. The staff concludes that the Unit 1 Periodic Inspection Program will be an acceptable mitigative action and compensate for the lack of operating experience in meeting the intent of the Rule.

1.3.2 License Renewal at Currently Licensed Power Level

Part 54 of 10 CFR describes the requirements for renewing operating licenses for nuclear power plants. The staff performed its technical review of the LRA in accordance with Commission guidance and the requirements of 10 CFR Part 54. Section 54.29 of 10 CFR sets forth the standards for renewing a license. This SER describes the results of the staff's safety review. The staff while performing the safety review limited its safety finding to matters related to the CLB and at the currently authorized power levels for which the units are licensed. These power levels are indicated in Section 1.1 of this SER’s Introduction and General Discussion. Even though the applicant’s original submittal dated December 31, 2003, included a renewal request at extended power uprate (EPU) conditions for the three BFN units, the applicant by its letter dated January 7, 2005, requested decoupling the power uprate request from the LRA. In that submittal the applicant requested that the staff complete the review based on the current licensed power level for each of the three units and address separately the EPU conditions after the renewed licenses are approved. Hence all the safety findings and staff evaluations apply to the currently authorized power levels for which each of the BFN units are currently licensed.

1.3.3 Integration of Unit 1 Restart Modification

Ever since March 1985, Unit 1 has been on administrative hold and the applicant has committed not to restart Unit 1 without prior approval from the staff. The applicant is currently planning to restart Unit 1 in 2007. The element unique to Unit 1 is that restart activities include modifying the Unit 1 licensing basis to make it consistent with the CLB of Units 2 and 3. During the meetings with the staff during 2003, it was agreed the applicant would identify in the LRA the Unit 1 differences that will be eliminated when restart activities are completed. To highlight these differences, information not yet applicable to Unit 1 was marked with bolded border. This annotation methodology is consistent with previous multi-plant LRAs submitted to the staff. LRA Appendix F describes each of these differences, its effect on the application, the schedule for resolution, and provides references to application sections affected. This enables the applicant to submit an LRA based on the CLB for all three units, as well as to identify Unit 1 restart activities relevant to the LRA. The changes are being implemented as part of Unit 1 restart activities consistent with the changes made previously to Units 2 and 3. Thus, the applicant states that the BFN units are essentially identical, and the application is not unit-specific with regard to AMPs or the AMRs.

1.3.4 Other Regulatory Requirements

In 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information. The applicant provided this general information in LRA Section 1, which it submitted by letter dated December 31, 2003.

In 10 CFR 54.19(b), the NRC requires that each LRA 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 the LRA regarding this issue:

> TVA requests that, as appropriate, conforming changes be made to the Article VII of the indemnity agreement, and item 3 of the Attachment to the agreement, specifying the extension agreement until the expiration date of the renewed facility operating licenses as sought in the application.

The staff intends to make conforming changes to the indemnity agreement so that the requirements of 10 CFR 54.19(b) will be met.

In 10 CFR 54.21, the NRC requires that each LRA must contain: (a) an IPA, (b) a description of any CLB changes that occurred during the staff review of the LRA, (c) an evaluation of TLAAs, and (d) an FSAR or a UFSAR supplement. Sections 3 and 4 and LRA Appendix B address the license renewal requirements of 10 CFR 54.21(a), (b), and (c). LRA Appendix A contains the license renewal requirements of 10 CFR 54.21(d).

In 10 CFR 54.21(b), the NRC requires that each year following submission of the LRA, and at least three months before the scheduled completion of the staff’s review, the applicant must submit an amendment to the renewal application that identifies any changes to the CLB of the facility that materially affect the contents of the LRA, including the UFSAR supplement. The applicant submitted an update to the LRA by letter dated January 31, 2005, which summarized the changes to the CLB that have occurred during the staff’s review of the LRA. This submission satisfies the requirements of 10 CFR 54.21(b) and is still under staff review.

In accordance with 10 CFR 54.22, an applicant's LRA must include changes or additions to the technical specifications (TSs) that are necessary to manage the effects of aging during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any TS changes necessary to support issuance of the renewed operating licenses for BFN.

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

As required by 10 CFR 54.25, the ACRS will issue a report to document its evaluation of the staff's LRA review and associated SER. SER Section 5 will incorporate the ACRS report once it is issued. SER Section 6 will document the findings required by 10 CFR 54.29.

The final plant-specific supplement to the GEIS was issued on June 23, 2005, and documents the staff's evaluation of the environmental information required by 10 CFR 54.23.

1.4 Interim Staff Guidance

The license renewal program is a living program. The NRC staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the staff's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders until it is incorporated into the license renewal guidance documents such as the SRP-LR and the GALL Report.

The following table provides the current set of ISGs issued by the staff, as well as the SER sections in which the staff addresses ISG issues.

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
GALL Report presents one acceptable way to manage aging effects **(ISG-1)**	This ISG clarifies that the GALL Report contains one acceptable way, but not the only way, to manage aging for license renewal.	N/A
SBO 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 EDGs. The offsite power system should be included within the scope of license renewal.	2.1.3
Concrete AMP **(ISG-3)**	Lessons learned from the GALL demonstration project indicated that GALL is not clear on whether concrete requires an AMP.	3.5.2.2.8

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
FP System Piping **(ISG-4)**	This ISG clarifies the staff position for wall-thinning of the FP piping system in GALL AMPs XI.M26 and XI.M27. The staff's new position is that there is no need to disassemble FP piping, as disassembly can introduce oxygen to FP piping, which can accelerate corrosion. Instead, a non-intrusive method, such as volumetric inspection, should be used. Testing of sprinkler heads should be performed at year 50 of sprinkler system service life, and every 10 years thereafter. This ISG eliminates the Halon/carbon dioxide system inspections for charging pressure, valve line-ups, and the automatic mode of operation test from GALL; the staff considers these test verifications to be operational activities.	3.0.3.2.17

ISG Issue (Approved ISG No.)	Purpose	SER Section
Identification and Treatment of Electrical Fuse Holders **(ISG-5)**	This ISG includes electrical fuse holders 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.	2.1.3.2.3 3.6.2.3.1
Scoping for fire protection equipment **(ISG-7)**	This ISG provides clarification of the fire protection systems, structures, and components scoping to whether the scope would expand to include (BTP) APSCB 9.5-1	2.1.3.1.2
The ISG Process **(ISG-8)**	This ISG provides clarification and update to the ISG process on Improved License Renewal Guidance Documents.	N/A

ISG Issue (Approved ISG No.)	Purpose	SER Section
Standardized Format for License Renewal Applications **(ISG-10)**	The purpose of this ISG is to provide a standardized license renewal application format for applicants.	N/A

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted to the staff through June 15, 2005, the staff identified the following open items (see below). An issue is considered open if the applicant has not presented a sufficient basis for resolution. Each open item (OI) has been assigned a unique identifying number.

OI-2.4-3: (Section 2.4 - Drywell Shell Corrosion)

Supplement 1 of Information Notice (IN) 86-99 indicates that, if leakage from the flooded reactor cavity is not monitored and managed, there is a potential for corrosion of the cylindrical portion of drywell shell. As this corrosion would initiate in the non-inspectible areas of the drywell, it cannot be monitored by IWE inspections. Moreover, this degradation of drywell shell can occur even if there is very little water found in the sand-pocket area of the drywell. Thus, the reactor building to drywell refueling seal becomes a non-safety-related (NSR) item that can affect the integrity of the drywell shell (which is a pressure boundary component) during the period of extended operation, and falls under the requirement of 10 CFR 54.4(a)(2). For two BWR plants, the staff accepted an alternative to managing the aging of the seal. The alternative is to periodically perform ultrasonic testing (UT) of the cylindrical portion of the drywell shell with an acceptable sampling program, as part of containment inservice inspection (ISI) program. After reviewing the response to RAI 3.5-4 (in the applicant's letter dated January 31, 2005) related to the operating experience of drywell shell corrosion at all three units, the staff came to the conclusion that the applicant should manage the aging (leakage) of refueling seals, therefore, this is identified as OI 2.4-3.

The applicant responded to OI 2.4-3 by letter dated May 31, 2005. BFN did not include the refueling seals at the top of the drywell in the scope of license renewal and provided the following technical basis for that conclusion: The drywell-to-reactor building refueling seal and the reactor pressure vessel (RPV)-to-drywell refueling seal, in conjunction with the refueling bulkhead, provide a watertight barrier to permit flooding above the RPV flange while preventing water from entering the drywell. Providing a watertight barrier to permit flooding above the RPV flange in support of refueling operations is an NSR function. In 10 CFR 54.4(a), the criteria that determine whether plant systems, structures, and components are within the scope of license renewal are set forth. The refueling seals do not satisfy any of the requirements set forth in 10 CFR 54.4(a)(1). The refueling seals are NSR, and they are not relied upon to remain functional during design basis events. Thus, the refueling seals are not brought within the scope of license renewal by 10 CFR 54.4(a)(1).

In a letter dated November 16, 2005, the applicant stated that for Unit 1 it will perform one-time confirmatory ultrasonic thickness measurements on the vertical cylindrical area immediately below the drywell flange. For Units 2 and 3, it will perform the same testing in the portion of the cylindrical section of the drywell in a region where the liner plate is 0.75 inches thick. This will provide a bounding condition since the nominal thickness of the wall in this region has the least margin. The applicant committed to perform these ultrasonic thickness measurements prior to the Unit 1 restart, and prior to the period of extended operation for Units 2 and 3. The staff found this acceptable; therefore, OI 2.4-3 is closed.

<u>OI-4.7.7</u>: (Section 4.7.7 - Stress Relaxation of the Core Plate Hold-Down Bolts)

In LRA Section 4.7.7, the loss of preload of the core plate hold-down bolts due to thermal and irradiation effects was evaluated in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). For the 40-year lifetime, the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-25 concluded that all core plate hold-down bolts will maintain some preload throughout the life of the plant. For the period of extended operation, the expected loss of preload was assumed to be 20 percent, which bounds the original BWRVIP analysis that was prepared to bound the majority of plants, including BFN units after operating for 20 additional years. With a loss of 20 percent in preload, the core plate will maintain sufficient preload to prevent sliding under both normal and accident conditions. Based on this assumption, the applicant concluded that the loss of preload is acceptable for the period of extended operation.

In RAIs 4.7.7-1, 4.7.7-2, and follow ups, the staff requested the applicant to demonstrate how the BWRVIP-25 analysis can be applied to the BFN units based on the configuration and the geometry of core plate hold-down bolts and the reactor environment (temperature and neutron fluence) assumed in the original report. In its letter dated September 6, 2005, the applicant provided the vendor's plant-specific calculations that will validate the assumptions as stated above. However, the staff found that the methodology used did not follow the staff's approved BWRVIP-25 analysis; therefore, it requested additional information. In its letter dated November 16, 2005, the applicant provided supplemental responses and identified several of the staff's concerns raised during a teleconference on October 18, 2005. The applicant took the staff's comments under advisement and committed to perform a plant-specific analysis consistent with BWRVIP-25. This analysis will be submitted for the staff's review two years prior to the period of extended operation. The staff considers this acceptable; therefore, OI 4.7.7 is closed.

<u>OI-3.0-3 LP</u>: (Section 3.0 - B.2.1.42, Unit 1 Periodic Inspection Program)

During the 526th meeting of the Advisory Committee on Reactor Safeguards, October 6-7, 2005, the ACRS reviewed the LRA for the BFN Units 1, 2, and 3, and the associated SER with open items prepared by the staff. Though the Committee agreed with the staff that periodic inspections of systems and components that were not replaced are appropriate and necessary, it was not clear which systems will be included in the scope of the Unit 1 Periodic Inspection Program, since no further attributes of this future program have been provided in the SER. The main attributes of the program, including the intended scope, need to be defined in the final SER. The Committee stated that periodic inspections are the most significant compensating actions for the lack of plant-specific operating experience of BFN Unit 1 and It was not possible to judge the adequacy of this important program since insufficient information has been provided. As a result of the Committee's review, the staff elevated this issue from a confirmatory item to an open item and requested the applicant to provide details of the periodic inspection program prior to issuance of the final SER. This is open item 3.0.3.

When the staff briefed the Committee on the SER with open items during the October 5-6, 2005 meeting, it omitted a description of this new plant-specific program called “B.2.1.42 - Unit 1 Periodic Inspection Program.” The SER described the staff's review of information submitted to the NRC through June 15, 2005, the cutoff date for consideration in the SER with open items. Staff has since received details of this AMP titled, “B.2.1.42 - Unit 1 Periodic Inspection Program.“ The staff review and evaluation of the program is included in this final version of the SER in Section 3.0.3.3.5. This closes open item 3.0.3.

1.6 Summary of Confirmatory Items

As a result of the staff's review of the LRA for BFN, including additional information and clarifications submitted to the staff through June 15, 2005, the staff identified the following confirmatory items (CIs). An issue is considered confirmatory if the staff and the applicant have reached a satisfactory resolution, but the resolution has not yet been formally submitted to the staff. Each CI has been assigned a unique identifying number. The items identified in this section have been properly closed by the technical staff.

CI 3.3.2.35-1: (Section 3.3 Bolting in Auxiliary Systems)

For auxiliary system closure bolting, the staff was concerned that cracking and loss of preload are not entirely addressed by either the American Society of Mechanical Engineers (ASME) Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program or Bolting Integrity Program. Although ASME Section XI requires bolt torquing loads to be in accordance with ASME Section III for replacement of Class 1 and 2 bolting, no bolt torquing requirements are specified for Class 3 bolting, NSR bolting or bolting that is reused after being removed for maintenance. The staff raised these issues in RAI 3.3.32.35-1.

The staff reviewed the applicant's response dated March 16, 2005, and found the response to be reasonable and acceptable. The applicant provided additional information to clarify that cracking and loss of preload in bolting are being effectively managed. However, the response did not provide the results of any self assessments, inspections, or maintenance activities, and operating experience to determine if closure bolting in auxiliary systems was effectively managed at BFN for cracking and loss of preload. The staff discussed this issue with the applicant in a teleconference, and the verification of this confirmatory item was addressed during the AMP inspection performed on September 2005. In the inspection report, letter dated November 7, 2005, the staff concluded that the bolting practices in BFN are functioning adequately; therefore, CI 3.3.2.35-1 is closed.

CI-B.2.1.36 (Section B.2.1.36, Structures Monitoring Program)

The staff had a follow-up question in a May 4, 2005, teleconference regarding evaluation of inspection personnel qualification based on industry guidance, the American Concrete Institute (ACI) 349.3R-96 as stated in the Structures Monitoring Program. The staff stated that this industry guidance alone will not be adequate to qualify the inspectors for the examination of steel supports for the Structures Monitoring Program. The staff requested that the applicant reevaluate the program element from previous staff positions and submit the description for staff review. In its response to a follow up to RAI B.2.1.33-1, by letter dated May 31, 2005, the applicant responded to the staff's question and committed (letter dated December 12, 2005) to manage the aging effects of Class MC supports under ASME Code Section XI Subsection IWF. The applicant also agreed to include the inspector's qualification in accordance with the requirements of ASME Code Section XI Subsection IWF and not per the BFN Structures Monitoring Program. The staff found this acceptable; therefore, CI-B.2.1.36 is closed.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the LRA, including subsequent information and clarifications provided by the applicant, the staff identified four 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, as required by 10 CFR 50.71(e), following the issuance of the renewed licenses.

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

The third license condition requires the implementation of the most recent staff-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as the method to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix H. Any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for NRC staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule which affects the time of withdrawal of any surveillance capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in a manner which maintains them in a condition which would support re-insertion into the reactor pressure vessel, if necessary.

The fourth license condition is satisfactory completion of the thirteen Unit 1 restart commitments that are discussed in LRA Appendix F (see SER Section 2.6). Successful completion of these restart activities provides a necessary regulatory framework for review of the LRA and is a staff assumption fundamental throughout the staff safety review. When completed, the CLB of Unit 1 will be consistent with the CLB of Units 2 and 3. Completion of these activities is a condition to be met prior to power operations of Unit 1.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application — Technical Information," requires that each application for license renewal contain an integrated plant assessment (IPA). Furthermore, the IPA must list and identify those structures and components that are subject to an aging management review (AMR) from the systems, structures, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4. LRA Sections 2.1.4 and 2.1.5 of the license renewal application (LRA) describe the applicant's process for identifying these structures and components (SCs) and provide the scoping and screening results for those components, subcomponents, structural members, and commodity groups that are subject to an AMR in accordance with LRA Section 3.0.

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

In developing the scoping and screening methodology, the applicant considered the requirements of the Rule, the Statement of Consideration (SOC) for the Rule, and the guidance presented by the Nuclear Energy Institute (NEI), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, March 2001, (NEI 95-10). In addition, the applicant considered the Nuclear Regulatory Commission (NRC) staff's correspondence with other applicants and with the NEI in the development of this methodology. Scoping and screening were performed as an integrated review at the system/structure level. Screening was performed on a component-level basis, and the scoping results were reviewed and revised as required to be consistent with the screening results. The short-lived passive components that could be excluded from an AMR on the basis of a qualified life or a specified replacement time period were identified and screened out as part of the AMR process.

2.1.2 Summary of Technical Information in the Application

In LRA Sections 2.0 and 3.0, the applicant provided the technical information required by 10 CFR 54.21(a). In LRA Section 2.1, "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 SCs that are subject to an AMR as required by 10 CFR 54.21(a)(1). LRA Section 2.1.2 discusses the application of the

10 CFR 54.4(a) scoping criteria; Section 2.1.3 provides a discussion of the documentation that was used to perform scoping and screening; and LRA Sections 2.1.4 and 2.1.5 describe the scoping and screening methodology.

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” amplify the process the applicant used to identify the SCs that are subject to an AMR. LRA Section 3, “Aging Management Review Results,” contains the following information:

- Section 3.1, “Aging Management of Reactor Vessel, Internals, and Reactor Coolant System”
- Section 3.2, “Aging Management of Engineered Safety Features Systems”
- Section 3.3, “Aging Management of Auxiliary Systems”
- Section 3.4, “Aging Management of Steam and Power Conversion Systems”
- Section 3.5, “Aging Management of Containment, Structures and Component Supports”
- Section 3.6, “Aging Management of Electrical and Instrumentation and Controls”

LRA Section 4, “Time-Limited Aging Analyses,” contains the applicant’s identification and evaluation of time-limited aging analyses (TLAAs).

2.1.2.1 Scoping Methodology

In LRA Section 2.1, the applicant described the methodology used to scope systems and structures pursuant to the requirements of 10 CFR 54.4(a). The applicant identified differences between the current licensing basis (CLB) for Unit 1 and the CLB for Units 2 and 3, and documented them in LRA Appendix F. The applicant stated that the differences between CLBs will be resolved before the restart of Unit 1, so that the CLB for Unit 1 will be consistent with Units 2 and 3. The applicant’s scoping methodology, as described in the LRA, is outlined in the sections below.

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

The applicant described the general approach to scoping SSCs that are safety-related (SR), nonsafety-related (NSR) affecting SR, or credited with demonstrating compliance with certain regulated events in LRA Section 2.1.2, “Application of Scoping Criteria in 10 CFR 54.4(a).” The scoping approaches specific to each of the three 10 CFR 54.4(a) scoping criteria are described in the following sections.

<u>Application of the Scoping Criteria in 10 CFR 54.4(a)(1)</u>. In LRA Section 2.1.2.1, "10 CFR 54.4(a)(1) - Safety-Related," the applicant discussed the scoping methodology as it relates to SR criteria in accordance with 10 CFR 54.4(a)(1). With respect to the SR criteria, if one or more of the three SR criteria were met, the applicant determined that the function was an SR intended function, and included the corresponding SR SSCs within the scope of license renewal that are relied upon to remain functional during and following/ a design basis event

(DBE) as defined in 10 CFR 50.49(b)(1) and are based on reviews of plant accident analyses and evaluations.

Application of the Scoping Criteria in 10 CFR 54.4(a)(2). In LRA Section 2.1.2.2, "10 CFR 54.4(a)(2) - Nonsafety-Related SSCs Whose Failure Could Prevent Satisfactory Accomplishment of Safety-Related Functions," the applicant discussed the methodology used to identify SSCs meeting the 10 CFR 54.4(a)(2) NSR license scoping criteria. Specifically, the applicant considered the following SSCs to be in the scope of 10 CFR 54.4(a)(2):

- SCs, such as pipe whip restraints, that provide protection to SR SSCs to be in the scope of 10 CFR 54.4(a)(1) rather than 10 CFR 54.4(a)(2) SSCs
- Liquid-filled NSR SSCs directly connected to SR SSCs
- NSR SSCs that are not directly connected to SR structures such as, reactor buildings, primary containment structures
- NSR air/gas and heating, ventilation, and air conditioning (HVAC) systems that could prevent the satisfactory accomplishment of an SR function

In LRA Section 2.1.2.2, the applicant described the methods and rationale used to scope each of the above categories of NSR SSCs in the LRA. The applicant's review encompassed the DBEs considered in these documents. The NSR SSCs already included within the scope of license renewal for 10 CFR 54.4(a)(3) were not identified for inclusion under 10 CFR 54.4(a)(2).

Application of the Scoping Criteria in 10 CFR 54.4(a)(3). In LRA Sections 2.1.2.3, "10 CFR 54.4 (a)(3) - The Five Regulated Events," and 2.1.3.4, "Specific Scoping Documents for Regulated Events," the applicant discussed the methodology used to identify SSCs credited in performing a function that demonstrates compliance with regulations for fire protection, environmental qualification (EQ), anticipated transient without scram (ATWS), and station blackout (SBO) pursuant to 10 CFR 54.4(a)(3) license renewal scoping criteria. The applicant did not address pressurized thermal shock (PTS) because Browns Ferry units are boiling water type reactors to which this criterion does not apply.

2.1.2.1.2 Documentation Sources Used for Scoping and Screening

In LRA Section 2.1.3, "Documentation Sources Used for Scoping and Screening," the applicant listed sources that were used as input during the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- safe shutdown analysis (SSA) calculation
- Maintenance Rule documentation
- CLB and design-basis documents (design criteria documents and calculations, qualitative assessments and analyses, quantitative computations)
- controlled plant component database (also known as enterprise maintenance planning and control (EMPAC))
- site drawings

The applicant stated that these sources were used to identify the functions performed by plant systems and structures. These functions were then compared to the scoping criteria in 10 CFR 54.4(a)(1)-(3) to determine if the associated plant system or structure performed a license renewal intended function. These sources were also used to develop the list of structures and components subject to an AMR.

2.1.2.1.3 Plant and System Level Scoping

In LRA Section 2.1.4, “Scoping Methodology,” the applicant stated that the scoping methodologies used to identify mechanical, electrical, and instrumentation and control (I&C) systems and structures were described under the respective disciplines. In general, the applicant created a list of systems and structures from the EMPAC, site drawings, and the structures’ design documents, UFSAR, Maintenance Rule documents, and other plant design documents. The methodologies for individual disciplines are discussed below.

Mechanical Component Scoping. In LRA Section 2.1.4.1, the applicant described the scoping methodology for components within SR and NSR mechanical systems. For every mechanical system, the applicant applied the following scoping process: (1) identify system intended functions, (2) determine system evaluation boundary, and (3) create license renewal drawings. The applicant used information from the SSA calculation, the UFSAR, and other applicable documents to identify those systems that perform intended functions as defined in 10 CFR 54.4(a)(1).

A summary was prepared for each system that listed the identified system intended functions and the 10 CFR 54.4 criteria that caused the system to be within the scope of license renewal. Those systems for which no functions were identified as satisfying any of the three scoping criteria were classified as systems outside the scope of license renewal, and no further evaluation was performed. After identifying the system intended functions, the applicant established the system evaluation boundary, which identifies the portions of the system that are required to perform an intended function. Included in the evaluation boundary are the passive, long-lived components needed for the system to perform its intended functions. The components within the system evaluation boundary were reviewed according to the criteria of 10 CFR 54.4(a) used during evaluation of the system.

Electrical and Instrumentation and Control System Component Scoping. In LRA Section 2.1.4.2, the applicant described the scoping methodology for components in SR and NSR electrical and I&C systems. Specifically, the applicant selected the electrical and I&C components from the EMPAC list and evaluated them against the 10 CFR 54.4(a) criteria. The applicant reviewed NEI 95-10, and BFN documents such as plant drawings and EMPAC to determine the complete set of electrical commodities installed at BFN. These electrical commodities were included in the license renewal scope for evaluation using the spaces approach. The spaces approach identified the electrical and I&C commodity groups that are installed in the plant and the limiting environmental conditions for each group. The only exception to the spaces approach was in the SBO offsite power restoration methodology. The applicant used the conventional system evaluation methodology (i.e., mechanical system scoping) to identify the system intended functions and subsequent SCs within the scope of license renewal. As part of this review, the applicant reviewed the SSA calculation, UFSAR descriptions, Maintenance Rule documents, CLB, and design-basis documents to determine the system's safety classification level, and to identify the system intended functions.

Structural Component Scoping. In LRA Section 2.1.4.3, the applicant described the scoping methodology for components within SR and NSR structures. Specifically, the applicant stated that the list of structures used for scoping was developed from the review of design drawings, design criteria document, and Maintenance Rule documentation, which include items such as free-standing buildings and structures, primary containment shell, tank foundations, manholes, tunnels, duct banks, and earthen structures. The applicant relied on the design criteria document for structures and the UFSAR to identify the safety classification of structures and structural components.

For review purposes, seismic Class I structures and structural components were considered SR. Structure functions were evaluated against the 10 CFR 54.4(a) criteria and structure intended functions were identified. The structure interfaces were examined and, in those instances where a failure of a structure could prevent a satisfactory accomplishment of any SR intended function or adversely impact other SR structures, that structure was identified and included within the scope of license renewal. The applicant reviewed detailed structural drawings for structures determined to be within the scope of license renewal to identify structural components. For structures within the scope of license renewal, all structural components required to support the intended functions were identified as within the scope of license renewal.

2.1.2.2 Screening Methodology

In LRA Section 2.1.5, "Screening Methodology," the applicant described the process of identifying the structures and components that are subject to an AMR. The applicant stated that, in accordance with 10 CFR 54.21(a)(1)(i), the screening process used the industry guidance contained in NEI-95-10, Revision 3, Appendix B, "Typical Structure, Component and Commodity Groupings and Active/Passive Determinations for the Integrated Plant Assessment," to identify SSCs from items within the scope of license renewal that require AMR. The identified SSCs were then sorted into groups that (1) perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties; and (2) those that are not subject to replacement based on a qualified life or specified time period. Components were then evaluated to determine which were long-lived. Components were considered long-lived unless specific plant documentation indicates the component is replaced at intervals of less than forty years.

2.1.2.2.1 Mechanical Component Screening

In LRA Section 2.1.5.1, the applicant described the component screening for mechanical systems as a continuation of the component scoping activity. The applicant evaluated each component within the scope of license renewal to determine if it has a passive function. If a component has a passive function that supports a system intended function, and if the component was determined to be long-lived, then the component was considered subject to an AMR. The applicant reviewed maintenance procedures, records, and vendor recommendations to determine if a component is long- or short-lived.

2.1.2.2.2 Structural Component Screening

In LRA Section 2.1.5.3, the applicant described the methodology used to screen the structural components within the scope of license renewal. The screening methodology classified in-scope structural components as passive consistent with the guidance found in NEI 95-10, Appendix B. In-scope structural components such as elastomers, which are subject to replacement in specified intervals, were considered short-lived and were excluded from an AMR. The structural screening included certain structural components in electrical systems (e.g., cable trays) and mechanical systems (e.g., pipe supports).

2.1.2.2.3 Electrical and Instrumentation and Control System Component Screening Methodology

In LRA Section 2.1.5.2, the applicant described the screening methodology for electrical and I&C components. The applicant had classified all electrical and I&C components within the scope of license renewal based on the spaces approach, with the exception of components in the SBO offsite power restoration flow path. Components were characterized as active or passive, based on NEI 95-10, Appendix B, guidance. Long-lived commodity groups were identified by using industry and BFN experience. The spaces approach identifies the electrical and I&C commodity groups that are installed in the plant and the limiting environmental conditions for each group. The spaces approach then determines if any area environment is more severe than the limiting environment for the commodity group. If the area environment is more severe than a commodity group's limit, and if a component in the commodity group is actually located in the area, an AMR is required for that commodity group.

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 U.S. Nuclear Regulatory Commission Regulatory Guide (NUREG)-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR). The acceptance criteria for the scoping and screening methodology review are based 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 used 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 staff reviewed the activities described in the following sections of the LRA using the guidance contained in the SRP-LR:

- Section 2.1, "Scoping and Screening Methodology," to verify that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), (a)(2), and (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 verify that the applicant described a process for determining structural, mechanical, and electrical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and (a)(2).

In addition, the staff conducted a scoping and screening methodology audit at the Tennessee Valley Authority (TVA) corporate offices in Chattanooga, TN, from June 7 to 10, 2004. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the application and the requirements of the Rule. The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology implemented by the applicant. In addition, the staff conducted detailed discussions with the applicant on the implementation and control of the license renewal program and reviewed administrative control documentation and selected design documentation used by the applicant during the scoping and screening process. The staff further reviewed a sample of system scoping and screening results reports for the residual heat removal service water (RHRSW) system and the emergency equipment cooling water (EECW) system to ensure that the methodology outlined in the technical evaluations was appropriately implemented and the results were consistent with the CLB.

2.1.3.1 Scoping Methodology

The scoping evaluations for the Browns Ferry Nuclear LRA were performed by the applicant's license renewal project personnel. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process. The staff assessed whether the scoping methodology outlined in the LRA and implementation procedures was appropriately implemented and whether the scoping results were consistent with CLB requirements.

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 structures and components subject to an AMR was consistent with the LRA and SRP-LR and that the applicant had appropriately implemented the procedural guidance. Additionally, the staff reviewed the scope of CLB documentation sources used to support the LRA development and the process used by the applicant to ensure that CLB commitments has been appropriately considered during the scoping and screening process.

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

0-TI-346	Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting
0-TI-455	Mechanical Technical Evaluations For License Renewal, Revision 2

0-TI-456	Electrical Technical Evaluations For License Renewal
0-TI-457	Civil Technical Evaluations For License Renewal
0-TI-458	License Renewal Time Limited Aging Analyses, Revision 1
NEDP-21	Technical Evaluations for License Renewal, Revision 2
NEDP-4	Q-list and UNID Control, Revision 7
NEDP-5	Design Document Reviews
SPP-3.1	Corrective Action Program, Revision 6
SPP-9.6	Master Equipment List, (MEL) Revision 6

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

In addition to the implementing procedures, the staff reviewed supplemental design information including design-basis documents, system drawings, and selected licensing documentation, that the applicant relied on during the scoping and screening phases of the review. The staff found these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the plant's CLB.

<u>Sources of Current Licensing Basis Information</u>. 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 UFSAR, and licensee commitments remaining in effect from docketed licensing correspondence such as applicant responses to NRC bulletins, generic letters (GLs), and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports. The applicant identified differences between the CLB for Unit 1 and the CLB for Units 2 and 3, and documented them in LRA Appendix F.

The staff determined that LRA Section 2.1.3 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, the applicant provided a comprehensive listing of documents that could be used to support scoping and screening evaluations. The applicant noted that system descriptions and system intended functions had been identified based on the review of the applicable sections of the UFSAR, Appendix B determinations, Maintenance Rule scoping document, and design and licensing basis documents.

Conclusion. Based on a review of information provided in LRA Section 2.1, 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 had considered a scope of CLB information generally consistent with the guidance contained in the SRP-LR and NEI 95-10.

Quality Assurance Controls Applied to LRA Development. The staff reviewed the quality assurance controls used by the applicant to verify that they provided reasonable confidence that the LRA scoping and screening methodologies had been adequately implemented. The applicant chose not to credit the existing 10 CFR 50, Appendix B quality assurance program for the development of the LRA. However, the applicant controlled the LRA development activities as follows:

- Written procedures and guidelines governed implementation of the scoping and screening methodology.
- All final in-scope and screening information was developed by a lead technical staff member and independently reviewed by an additional technical staff member prior to being reviewed and approved by the program manager.
- The applicant developed a formal database for documenting license renewal information identified during in-scope and screening evaluations. This database was controlled in accordance with written instructions, and access to it was strictly controlled.
- The LRA was reviewed and approved by an independent expert committee comprised of experienced members of the TVA corporate engineering staff and BFN personnel.
- The applicant conducted two program peer reviews and one self-assessment of LRA activities to validate the implementation process and the technical accuracy of the application.
- The applicant instituted a training program, which required all participants in LRA activities to be certified to perform LRA activities and to attend training on the use of procedures, guidance documents, computer programs, and drawings.

Conclusion. The staff concluded that these quality assurance activities, which exceeded current regulatory requirements, provided additional assurance that LRA development activities were performed consistently with the LRA descriptions.

Training for License Renewal Project Personnel. The staff reviewed the applicant's implemented training process to ensure the guidelines and methodology for the scoping and screening activities would be performed in a consistent and appropriate manner. The applicant's LRA staff consisted of several engineers and contractors who had gained previous license renewal experience working on the Edwin I. Hatch LRA. The purpose of the training was to provide a framework for ensuring that the staff assigned to the technical portion of the LRA acquired a fundamental level of knowledge of the license renewal process and regulatory requirements. BFN used the Nuclear Engineering Design Procedure (NEDP)-7, Engineering Support Personnel Training, Revision 12, dated January 29, 2004, to impart training to all personnel involved in the LRA activities. Other documents used in the training include NEDP-7 Qualifications Guides (QGs), Task-Specific QGs, License Renewal Program, NEDP-21, Technical Evaluation for License Renewal, the *Code of Federal Regulations*, and NEI 95-10, Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule.

The staff reviewed the completed qualification and training records of several of the applicant's license renewal staff, including both experienced and non-experienced members, who performed scoping and screening activities. The staff did not identify any adverse findings.

Additionally, based on discussions with the applicant's license renewal personnel during the audit, the staff verified that the applicant's license renewal staff were knowledgeable concerning the license renewal process requirements and the specific technical issues within their areas of responsibility. The staff found that the applicant's license renewal training records were considered quality-related records and that these records were accurate, comprehensive, and complete.

Conclusion. The results from the scoping and screening audit indicate that the applicant considered the information in the CLB for Units 1, 2, and 3 in developing the scoping and screening methodology. The CLB documentation review methodology was capable of identifying the intended functions of the SSCs in a manner consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21. In addition, the applicant applied appropriate quality controls during the development of the application and adequately trained the applicable personnel. The staff concluded that the applicant had considered all relevant information during the preparation of the scoping and screening methodologies.

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

The staff evaluated the application of the scoping criteria for the methodology for scoping SR- and NSR-related SSCs and SSCs relied upon to demonstrate compliance with regulated events pursuant to 10 CFR 54.4(a). The results of the staff's evaluation are described below.

Application of the Scoping Criteria in 10 CFR 54.4(a)(1). Pursuant to 10 CFR 54.4(a)(1), the applicant must consider all SR SSCs that are relied upon to remain functional during and following DBEs to ensure the following functions: (1) maintain the integrity of the reactor coolant pressure boundary, (2) maintain the ability to shut down the reactor and maintain it in a safe shutdown condition, or (3) maintain the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2) or 10 CFR 100.11.

During the scoping and screening methodology audit, the staff questioned how non-accident DBEs, particularly DBEs that may not be described in the UFSAR, were considered during scoping. The applicant responded by identifying the DBEs applicable to BFN, including external hazards such as fire, earthquakes, flooding, wind and missiles, and high-energy line breaks. Additional DBEs were evaluated in the SSA calculation that was used by the applicant as a primary source for the purposes of identifying SSCs within the scope of license renewal. The SSA calculation was reviewed by the staff and discussed with the applicant. The staff found that the report contained a concise and detailed evaluation of approximately 35 events, and included appropriate CLB documentation references to support the review. The staff concluded that the applicant considered a scope of DBEs that was consistent with the guidance contained in the SRP-LR.

In addition, the staff evaluated the guidance documents governing the applicant's evaluation of SR SSCs: specifically, BFN standard department procedures; NEDP-5, "Design Document Reviews," Revision 2; NEDP-21, "Technical Evaluations for License Renewal," Revision 2; and license renewal instruction series 0-TI-455 through 458. Guidance was established for the preparation, review, verification, and approval of the scoping evaluations to assure the adequacy of the results of the scoping process. During the scoping and screening audit the staff reviewed the guidance and discussed the scoping approach with the applicant. Specifically, the staff reviewed a sample of the license renewal scoping results for the residual heat removal (RHR) system to provide additional assurance that the applicant adequately implemented its SR scoping methodology. The system scoping sheet identified the RHR system as SR with additional NSR systems supporting its operation. The evaluation identified the RHR system as meeting several of the 10 CFR 54.4(a)(3) criteria including: (1) EQ, (2) fire protection, and (3) SBO. All the system safety descriptions were listed, and the licensing basis calculations supporting those determinations were appropriately referenced. The report identified the cognizant license renewal staff members who prepared and verified the results. The applicant documented the information on a scoping results form. The applicant created a license boundary drawing in which every component in the system was identified by its unique component identifier (UNID) number, the description of the component, whether it was SR or NSR, whether it supported any of the regulated events, and the commodity material group to which it belonged (valve or pump etc.). The staff determined that the applicant identified and used pertinent engineering and licensing information to support the scoping determinations for the items sampled, and found the preparation, review, and approval of the scoping results to be effective for the development and evaluation of SR functions and subsequent identification of SSCs within the scope of license renewal.

The applicant reviewed the license renewal drawings in conjunction with physical drawings and component listings from EMPAC to determine the in-scope components that met the SR scoping criterion. All components identified as SR using the SR classification field in the EMPAC were considered for inclusion within the scope of the license renewal project. The applicant noted that the EMPAC safety-classification field was prepared many years ago using a definition for SR that was not necessarily the same as the definition of SR as described in the Rule. The staff reviewed the safety classification criteria used to determine the EMPAC safety classification to verify consistency with the 10 CFR 54.4(a)(1) criteria. The staff determined that the nuclear SR definition used by the applicant in its safety classification program did not include all the exposure limitations referenced in 10 CFR 54(a)(1)(iii). Specifically, procedures BFN-50-739, "Classification of Structures, Systems, and Components, Revision 3," and NEDP-4, "Q-list and UNID Control, Revision 7," did not include a reference to the offsite exposure limitations contained in 10 CFR 50.67(b)(2) for use of an alternate source term (AST).

Based on the above, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's request for additional information (RAI) as discussed below.

In RAI 2.1-1, dated July 30, 2004, the staff requested the applicant to provide additional information to describe the SR classification definitions that were used in developing the list of SSCs for the license renewal scoping and screening process, and describe how the offsite exposure limitations were factored into the LRA.

In its response, by letter dated September 3, 2004, the applicant stated:

> Consistent with 10 CFR 54.4(a)(1)(iii), BFN utilized a definition of safety-related that incorporated potential offsite exposures as follows: "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, as applicable." The applicable regulation for BFN is 10 CFR 100.11. 10 CFR 50.34 applies to applications for a construction permit and as such is not applicable to BFN. 10 CFR 50.67(b)(2) is applicable to plants revising their current accident source term to Alternative Source Term (AST). TVA has submitted a request for an amendment to the BFN Units 1, 2, and 3 facility operating licenses supporting a full scope application of the AST methodology. The application of AST is not approved by NRC hence, 10 CFR 50.67(b)(2) is not applicable to BFN. The BFN safety-related equipment classification and the SSCs included in the scope of license renewal continue to be based on potential offsite exposures contained in 10 CFR 100. Based on a review of TVA's AST submittal it is expected no new systems or component types will be added within the License Renewal scope that are not already identified in the application.

On September 27, 2004, the staff approved the applicant's license amendment request regarding AST per 10 CFR 50.67(b)(2) for offsite dose exposure as the CLB for BFN. Since the definition of SR components as applied to the scoping of components in the LRA can be either 10 CFR 50.67(b)(2) or 10 CFR 100.11, as applicable, and the AST submittal did not add new components within the LRA scope, it does not impact the SR definition. Hence the staff concluded that, consistent with 10 CFR 54.4(a)(ii), BFN utilized a definition of SR that included the capability to shut down the reactor and maintain it in a safe shutdown condition. The staff determined that the applicant's response is acceptable. The staff's concern described in RAI 2.1-1 is resolved.

Conclusion. The staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(1) scoping results and discussed the methodology and results with the applicant's license renewal project personnel. The staff verified that the applicant had identified and used pertinent engineering and the CLB in order to determine the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criteria. On the basis of a review of the applicant's methodology and evaluation of a sampling of scoping results and responses to the staff's RAI, the staff concluded that the applicant's SR scoping methodology provided reasonable assurance that SSCs meeting the scoping criteria of 10 CFR 54.4(a)(1) were included within the scope of license renewal.

Application of the Scoping Criteria in 10 CFR 54.4(a)(2). Section 54(a)(2) of 10 CFR requires, in part, that the applicant consider all NSR SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54(a)(1)(i), 10 CFR 54(a)(1)(ii), or 10 CFR 54(a)(1)(iii) to be within the scope of the license renewal.

In addition, by letters dated December 3, 2001, and March 15, 2002, the NRC issued a staff position to the NEI, which described areas for applicants to consider and options it expects applicants to use to determine which SSCs meet the 10 CFR 54.4(a)(2) criterion (i.e., all NSR SSCs whose failure could prevent satisfactory accomplishment of any SR functions identified in paragraphs 10 CFR 54.4(a)(1)(i)-(iii)). The December 3, 2001, letter provided specific examples of operating experience that identified pipe failure events (summarized in Information Notice

(IN) 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor") and the approaches the staff considers acceptable to determine which piping systems should be included within the scope of license renewal based on the 10 CFR 54.4(a)(2) criterion. The March 15, 2002, letter, further described the staff's expectations for the evaluation of non-piping SSCs to determine which additional NSR SSCs are within the scope of license renewal. The position states that applicants should not consider hypothetical failures, but, instead, should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation would include generic communications and event reports, plant-specific condition reports, industry reports such as significant operating experience reports (SOERs), and engineering evaluations.

As stated in the LRA, the applicant had included in the scope of license renewal NSR SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4(a)(1)(i)-(iii). The applicant identified SSCs satisfying criterion 10 CFR 54.4(a)(2) based on review of applicable CLB and engineering design bases and design documents, plant-specific and industry operating experience, and industry guidance documents.

The applicant documented the review of scoping activities in support of 10 CFR 54.4(a)(2) in an engineering report titled "10 CFR 54.4(a)(2) Scoping Methodology." The applicant discussed the scoping methodology as it related to the NSR criteria in accordance with 10 CFR 54.4(a)(2). With respect to the NSR criteria, the applicant stated that a review had been performed to identify the NSR SSCs whose failure could prevent satisfactory accomplishment of the SR intended functions identified in 10 CFR 54.4(a)(1).

As stated in the LRA, the applicant identified NSR SSCs whose failure could prevent satisfactory accomplishment of a safety function. The impacts of NSR system, structure, and component (SSC) failures were considered as either functional or spatial. In a functional failure, the failure of an SSC to perform its normal function impacts a safety function. In a spatial failure, a safety function is impacted by the loss of structural or mechanical integrity of an SSC in physical proximity to an SR component.

<u>Functional Failures of Nonsafety-Related SSCs</u>. In general SSCs required to perform a function in support of SR functions were classified as SR and included in the scope of license renewal per 10 CFR 54.4(a)(1). For the exceptions where NSR SSCs are required to remain functional in support of an SR function (and were not classified as SR), the supporting SSCs are included within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

<u>Overhead-Handling Systems</u>. Overhead-handling systems located in structures that contain SR SSCs were considered in scope if they had the ability to drop a load resulting in damage to an SSC that prevents satisfactory accomplishment of an SR intended function.

<u>Nonsafety-related SSCs Directly Attached to Safety-Related SSCs</u>. The applicant used a spaces approach and included all NSR liquid-filled piping and the corresponding supports that were located in buildings or structures that contain SR equipment within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), with exceptions as discussed below. The

applicant used plant drawings, such as flow diagrams, physical drawings, and isometric drawings to determine which systems, or portions of systems, were located in each building or structure. The applicant indicated that, by including within the scope of license renewal all NSR piping and corresponding supports in buildings or structures that contain SR equipment, the need to identify the piping up to the first seismic anchor was eliminated and that at the point where an NSR system leaves the building or structure that contains the SR SSCs and enters a building or structure that contains no SR SSCs, the NSR piping and supports are no longer within the scope of license renewal.

The staff discussed the spaces approach with the applicant and determined that, since all NSR piping and supports in the SR structure were considered within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), the applicant had not identified any “equivalent anchors” as a scoping boundary, but, instead, had marked scoping boundaries at the structure wall. The staff reviewed license renewal boundary drawing 1-47E801, which showed the four main steam lines in red (denoting within scope) in the reactor building. Where the main steam line piping exited the reactor building and entered the turbine building, the color changed from red to black, denoting the change from within scope to outside the scope of license renewal.

The staff’s review of LRA Section 2.1 identified areas in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAIs as discussed below.

In RAI 2.1-2A, dated July 30, 2004, the staff requested the applicant provide the following:

1. A description of the criteria used to determine that the integrity of the in-scope piping functions will be preserved if an age-related degradation failure occurs in the attached NSR piping.
2. A description of how it was determined that the SR piping in the reactor building is adequately supported so that it will remain functional if an age-related degradation occurs in the attached NSR piping in the turbine building.
3. A description of how the methodology ensured that the NSR piping up to first equivalent anchor point was included within the scope of license renewal.

The applicant responded to RAI 2.1-2A(1) and (2) by letters dated September 3, 2004, and October 18, 2004. In those responses, the applicant described the evaluation of SR and NSR portions of the main steam piping system. Specifically, the applicant stated, in part, that the seismic Class I portions of the four main steam lines have anchors isolating them from the seismic Class II piping. The seismic Class I/II interface is at the anchor. The piping up to the anchor is designed to seismic Class I requirements. The anchor locations are inside the reactor building, outboard of the isolation valves. The piping up to the anchor, and the anchor, is included within the scope of license renewal per 10 CFR 54.4(a)(1).

The NSR piping segments extending from the anchors to the reactor building/turbine building interface are qualified to seismic Class II pressure retention requirements to support secondary containment. Since secondary containment is an SR function, these piping segments are in the scope of license renewal and are shown in red on the license renewal drawing. This is consistent with BFN’s scoping methodology document which states that some NSR SSCs have been determined to perform SR intended functions (e.g., secondary containment, or main steam alternate leak path). As such, the applicant identified all piping supports, and other components inside secondary containment that are required to maintain the structural integrity of the secondary containment and verified that these SSCs were brought into scope. Additionally, the applicant stated that it would identify any additional piping, supports, and other components outside secondary containment that are required to maintain the structural integrity of the secondary containment prior to the period of extended operation.

After review of the information provided by the applicant regarding its evaluation, the staff held a teleconference with the applicant on May 3, 2005, and informed the applicant that any additional SSCs outside secondary containment necessary to maintain the structural integrity of the secondary containment must be identified and evaluated for aging effects as part of the current license renewal activities. As a result, the applicant performed a supplemental review of the SSCs associated with the secondary containment piping to identify those that are necessary to maintain the structural integrity of the secondary containment. This supplemental review was provided to the staff in a letter from the applicant, dated May 31, 2005. Specifically, the applicant described its supplemental review process, which included a review of plant drawings and piping system qualification documentation and performance of plant system walkdowns to identify the NSR piping, supports, and other components that are within the scope of license renewal for 10 CFR 54.4(a)(2) for secondary containment qualification. The results of this supplemental review identified several system boundary changes and identification of several new component types, materials, or environments that affected the AMR results. Details of the scoping results that expanded the boundaries of these systems and revisions to the AMR results are discussed in SER Sections 2.3, 2.4, and 3.5, respectively.

Based on the applicant's supplemental evaluation of SSCs associated with the secondary containment, which included a review of plant system drawing, piping and support qualification documentation, and extensive plant system walkdowns, the staff determined that the applicant had performed an adequate analysis to identify certain additional piping, components, and structures to be included within the scope of license renewal. The staff concluded that the analysis and inclusion of additional SSC's within the scope of license renewal adequately addressed RAI 2.1-2A(1) and (2). Therefore, the staff's concerns described in the RAI are resolved.

By letters dated September 3, 2004, October 18, 2004, January 31, 2005, and February 28, 2005, the applicant addressed RAI 2.1-2A(3) as discussed below.

The applicant indicated that during the restart of Units 2 and 3, and during the current restart process for Unit 1, the seismic Class I qualification documentation had been updated to ensure that the analyzed configuration reflected the as-built configuration. This documentation implements the CLB and provides the information necessary to determine the NSR piping and components that are necessary to maintain qualification of the connected SR piping and components. To ensure the license renewal boundaries are consistent with the CLB requirements, the applicant performed a review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, and other components that are within the scope of license renewal for 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

This review included the verification of each seismic Class I boundary identified in the CLB. The seismic Class I boundaries could typically be included in one of the following categories:

- Base-Mounted Equipment (pump, heat exchanger, tank, etc.) – a rugged component that is designed to provide support for connected piping and impose no loads on the piping. The review assures that when base-mounted equipment implements a seismic Class I boundary, the piping from the boundary to the equipment, and the equipment itself, are included within the scope of license renewal.
- Pipe Anchor – a special pipe support, which resists all six degrees of freedom, that has been designed and installed on the piping. The review assures that when a pipe anchor implements a seismic Class I boundary, the piping from the boundary to the pipe anchor, and the pipe anchor itself, are included within the scope of license renewal.
- Embedded Piping Segment – where piping is structurally attached (usually welded) to piping that is embedded in a concrete floor or wall and acts as an anchor. The review assures that when an embedment implements a seismic Class I boundary, the piping from the boundary to the embedment, and the embedment itself, are included within the scope of license renewal.
- Large Run Line – when a branch line moment of inertia is significantly smaller than a run line's moment of inertia, the branch line can be decoupled from the run line. The run line is then considered as an equivalent anchor. The review assures that in a case in which a large run line forms a seismic Class I boundary, the large run line is included within the scope of license renewal.
- Piping Free End – piping qualified up to an end that has no structural connection. The review assures that when a seismic Class I boundary is formed by a piping free end, all of the piping and supports from the boundary to piping free end(s) are included within the scope of license renewal.
- Flexible Connection – where a pipe stress analysis terminates at a flexible connection that is considered as a free end in that analysis. The review assures that when a flexible connection forms a seismic Class I boundary, the piping and supports from the boundary to the flexible connection are included within the scope of license renewal.
- Overlap Regions – where a series of single or multidirectional pipe supports have been installed to isolate one region of piping from another. The review assures that when an overlap region forms a seismic Class I boundary all of the piping and supports in the overlap region are included within the scope of license renewal.

The applicant indicated that the results of the review brought new portions of piping, components of existing systems, and two additional structures within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2).

The staff determined that the applicant had performed an analysis that defined several types of seismic Class I boundaries and had appropriately used this information to identify certain additional piping, components, and structures to be included within the scope of license renewal. The staff concluded that the analysis and inclusion of additional SCs within the scope of license renewal adequately addressed RAI 2.1-2A(3). Therefore, the staff's concern described in RAI 2.1-2A(3) is resolved.

<u>Nonsafety-Related SSCs in Proximity of Safety-Related SSCs</u>. The applicant used a spaces approach and included all NSR liquid-filled piping and the corresponding supports that are located in buildings or structures that contain SR equipment within scope in accordance with

10 CFR 54.4(a)(2), with exceptions as discussed below. The applicant used plant drawings, such as flow diagrams, physical drawings, and isometric drawings to determine which systems, or portions of systems, are located in each building or structure.

NSR high-energy piping located in buildings or structures that contain SR equipment was included within the scope of license renewal per 10 CFR 54.4(a)(2). The applicant had taken an exception to this approach by not including within the scope of license renewal the NSR pipe located in the SR-classified turbine building, although twelve SR main steam tunnel temperature switches are located in the main steam tunnel portion of the turbine building. In addition to the main steam lines, the main steam tunnel houses other NSR piping and components. The staff was unable to determine if the applicant demonstrated that the twelve temperature switches installed in the steam tunnel portion of the turbine building are adequately protected from age-related degradation of NSR SSCs.

In RAI 2.1-2B, dated July 30, 2004, the staff requested the applicant to address whether the 12 temperature switches installed in the main steam tunnel portion of the turbine building are adequately protected from wetting or spraying from the failure of NSR SSC components due to age-related degradation.

In its responses, by letters dated September 3, 2004, and October 18, 2004, the applicant addressed RAI 2.1-2B.

The applicant indicated that a design change notice (DCN) will be developed that will qualify the circuits for wetting and spray from a moderate/low-energy line break. The DCN will replace the temperature switch connectors and will also seal conduits as required to ensure circuit integrity and to mitigate the consequences of a moderate/low-energy line break. The applicant indicated that identification of moderate/low-energy, liquid-filled piping systems located in the vicinity of the temperature switches was not necessary since the switches will be qualified for the environment that would result from a moderate/low-energy line break. The applicant indicated that the DCN will be implemented prior to the period of extended operation.

The staff reviewed the response to RAI 2.1-2B and determined that the applicant had indicated that a DCN would be issued to modify the temperature switches located within the main steam tunnel such that they would be qualified to perform in an environment resulting from a moderate/low-energy line break. Therefore, the staff concern described in RAI 2.1-2B is resolved.

NSR moderate/low-energy piping located in buildings or structures that contain SR equipment was generally included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The exceptions to inclusion within scope were identified in the LRA as the turbine building (discussed above), intake pumping station, and the RHRSW tunnel.

In RAI 2.1-2C, dated July 30, 2004, the staff stated that in engineering report “10CFR54.4(a)(2) Scoping Methodology,” the applicant discussed the basis for exclusion of moderate/low energy piping located within the intake pumping station and RHRSW tunnel. The report stated that active SR components located within the intake pumping station were environmentally qualified and were normally exposed to outside weather conditions. In addition, the water from the NSR moderate/low energy pipe in the intake pumping station would not adversely affect the passive SR components (pipes or manual valves) since degradation would occur gradually over a period of time and system leakage would be detected prior to such degradation by plant personnel during activities such as operator rounds, routine radiation protection surveys or system engineer walkdowns. The same basis was applied to the potential effect of fluid from NSR SSCs on SR SSCs within the RHRSW tunnel (which only contain passive SR SSCs). Therefore, the staff requested that the applicant provide the additional information concerning the basis for the conclusion that failure of moderate/low energy fluid-filled NSR SSCs in the proximity of passive SR SSCs will not adversely affect the SR SSCs.

By letters dated September 3, 2004, and October 18, 2004, the applicant addressed RAI 2.1-2C, as discussed below.

The applicant reviewed the NSR fluid piping systems contained in the RHRSW tunnel and determined that all piping systems are within the scope of license renewal, with the exception of the 24-inch raw cooling water discharge piping, which was subsequently included within the scope of license renewal. The applicant indicated that exposure duration was not used in the scoping process.

In addition, the applicant reviewed the effect of water spray from NSR systems at the intake pumping station structure. The applicant determined that the SR equipment located within the intake pumping structure was designed for a normal operating environment of outside air, which includes precipitation and operation in a wetted environment. The applicant revised its scoping methodology to address components located in the lower compartments of the intake pumping station, which are subject to submergence during the probable maximum flood. The applicant determined that all SR passive electrical components installed at the intake pumping station are located above probable maximum flood level and are designed to either be protected from the effects of a wetted environment or designed to perform their function in a wetted environment. The applicant indicated that exposure duration was not used in the scoping process.

The staff reviewed the response to RAI 2.1-2C and determined that the applicant had not taken credit for exposure duration to exclude any NSR piping located within the RHRSW tunnel from scoping consideration. The applicant had included all applicable NSR piping within the scope of license renewal for the RHRSW tunnel. In addition, the applicant had determined that SR components in the intake pumping station, that are located above the probable maximum flood level are either protected from the effects of a wetted environment or designed to perform their function in a wetted environment. The staff concluded that this adequately resolved RAI 2.1-2C.

<u>Conclusion</u>. On the basis of the additional information supplied by the applicant, including determining that certain additional SSCs that would be placed within the scope of license renewal based on analysis and additional review, determining that certain SSCs were qualified for the environment, identifying the basis for the definition and use of the first equivalent anchor, and reviewing the results of NRC inspection and audit activities, the staff concluded that the applicant had supplied sufficient information to demonstrate that all SSCs that meet the 10 CFR 54.4(a)(2) scoping requirements have been identified as being within the scope of license renewal.

<u>Application of the Scoping Criteria in 10 CFR 54.4(a)(3)</u>. Section 54(a)(3) of 10 CFR requires, in part, that the applicant consider all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection

(10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) to be within the scope of license renewal.

The applicant performed the initial scoping for regulated events by evaluating CLB information relevant to each regulated event to identify if the structure or system met the scoping criteria of 10 CFR 54.4(a)(3). For these events, the applicant developed an engineering report describing the relevant Rule requirements. A functional description of the implementation includes the process to identify the scoping boundaries associated with the systems credited, the intended functions applicable to the requirement, information on how to record the results of the evaluation in the license renewal database and appropriate MEL, a list of CLB information sources used for the analysis, and a list of systems and components determined to be within scope for the given regulated event.

- Fire Protection. The applicant provided a description of the scoping of SSCs required to demonstrate compliance with the fire protection requirements in 10 CFR 50.48. The applicant stated that the fire protection report, EMPAC, and the CLB had been reviewed to ensure that SSCs required to perform the necessary safe shutdown functions and to minimize the risk of radioactive releases to the environment during and following fires are included within the scope of license renewal. In addition, the applicant stated that it considered the NRC's Interim Staff Guidance (ISG) related to scoping fire protection equipment, ISG-07, to determine if a system performs a function that demonstrates compliance with NRC's regulations. Specifically, the applicant verified that the EMPAC contains a designated field identifying components that are part of the fire protection program consistent with the CLB. The staff reviewed the process used by the applicant to identify those components and verified, through review of a selection of scoping results, that the EMPAC information was adequately incorporated into the license renewal evaluation.
- Environmental Qualification. The applicant stated that BFN maintains documents containing detailed information related to environmental qualification of components at BFN. Additionally, EMPAC provides a list of components that are subject to an EQ program. The applicant reviewed these documents to prepare the list of in-scope items for the LRA. Specifically, EMPAC contains a designated field identifying components that are part of the EQ program. The staff reviewed the process used by the applicant to identify those components and verified, through review of a selection of scoping results, that EMPAC information was adequately incorporated into the license renewal evaluation.
- Anticipated Transient Without Scram. The applicant reviewed UFSAR Section 7.19 and used the quality-related classification field in EMPAC to identify components of the ATWS mitigation system required by 10 CFR 50.62. EMPAC is a controlled plant component database containing integrated design and maintenance record management information. The plant component database lists plant components at the level of detail for which discrete maintenance or modification activities are typically performed. Specifically, EMPAC contains a designated field identifying components that are credited for ATWS mitigation. The staff reviewed the process used by the applicant to identify those components and verified, through review of a selection of scoping results, that the EMPAC information had been adequately incorporated into the license renewal evaluation.

- Station Blackout. In an NRC letter dated April 1, 2002, the staff provided guidance on the scoping of equipment relied on to meet the requirements of the SBO rule, 10 CFR 50.63. In this letter, the staff noted that, consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), 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.

In LRA Section 2.1.8.2, the applicant stated that, based on the guidance in the April 1, 2002, letter for SBO recovery, an evaluation was performed to determine, and bring into the scope of license renewal, components credited for recovery of the offsite power system. For each of the systems credited for SBO recovery, the applicant used, as a minimum, information from the SBO calculations and Emergency Operating Procedures and Technical Specification Bases 3.8.1, to determine the appropriate NSR portions of the in-plant electrical system that would be used to connect the offsite power system to the SR portions of the plant electrical system. The applicant performed calculations to summarize the results of a detailed review of SBO CLB documentation. The calculations provided lists of systems with their credited functions and a listing of major components. The applicant did not use the spaces approach to evaluate all plant electrical and I&C components in the SBO offsite power restoration flow path. The applicant provided license renewal drawings that identified the additional components in the offsite power restoration flow paths from 500 kilovolt (kV) and 161 kV switchyards to the plant SR shutdown buses using plant procedures for the restoration of offsite power.

Additionally, an AMR was performed for all long-lived passive structures and components within these systems. A scoping effort identified structures and components of the offsite power system for each plant required to restore power from the onsite switchyard down to the SR busses in the plant. The applicant also stated that the plant offsite power system and these structures and components were classified as satisfying10 CFR 54.4(a)(3) criteria and were included within the scope of license renewal. The staff determined that the applicant's approach to scoping SSCs relied on to demonstrate compliance with the SBO rule (10 CFR 50.63) was consistent with the staff's April 1, 2002, interim guidance.

Conclusion. The staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(3) scoping results and discussed the methodology and results with the applicant's license renewal project personnel. The staff verified that the applicant had identified and used pertinent engineering and licensing information to identify SSCs to be within the required scope in accordance with the 10 CFR 54.4(a)(3) criteria. On the basis of this sample review, discussions with the applicant, and review of the applicant's scoping process, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(3) was adequate.

2.1.3.1.3 System Level Scoping of Structures and Components

The applicant started the system-level scoping of structures and components with the review of the SSA calculation, UFSAR descriptions, Maintenance Rule documents, CLB, and design-basis documents to determine the system safety classification level functions and to identify the system intended functions. The SSA provided the system designation and the system function. The relevant flow drawings were retrieved for the system and description, and their safety classifications were determined. The components were identified and their functions were mapped. The applicant consulted the UFSAR to see if any additional functions were listed therein, because the applicant created the SSA during the restart of Units 2 and 3, listing all the possible system functions.

At the system level, the scoping methodology used for electrical and I&C systems was identical to the mechanical system-level scoping. The SSA calculation, UFSAR descriptions, Maintenance Rule documents, and other design-basis documents were reviewed to determine an electrical system's safety classification and to identify the electrical system's intended functions. System-level functions were evaluated against the criteria of 10 CFR 54.4(a). This information was included in the license renewal database for inclusion in the LRA.

The applicant entered the information on the "System Scoping Results" data sheet for the specific system. The staff reviewed the scoping results for the RHR system and observed that the data sheet contained detailed information that identified each component and its parent system, component type, the scoping criteria that it was required to meet, and its associated AMR information.

2.1.3.1.4 Component Level Scoping

The applicant reviewed license renewal boundary drawings in conjunction with physical layout drawings and component listings from EMPAC to determine the components within the scope of license renewal. Any component that was needed to fulfill any system intended function or determined to be an NSR component that could prevent satisfactory accomplishment of an SR function was considered to be within the scope of license renewal. The applicant evaluated the components either individually or in groups of like components and functions to ensure that all components were properly addressed. Electrical and I&C components of in-scope mechanical systems were classified as electrical and I&C commodities. Structural components of in-scope mechanical systems were classified as structural commodities. Structural commodities, such as cable trays and their supports, were classified as plant civil system commodities. Pressure boundary components of electrical penetrations were classified as civil commodities. Structural components of in-scope structures that are required to support the intended functions were generally evaluated as generic structural commodities, and not individual components.

<u>Mechanical Component Scoping</u>. The staff reviewed 0-TI-455, "Mechanical Technical Evaluation for License Renewal," Revision 2, dated May 28, 2004. The applicant provided a technical description and overview of the process in Section 4.1, Mechanical Scoping and Screening, of 0-TI-455. Specifically, the applicant stated that systems and components are determined to be within the scope of license renewal if they have been evaluated to meet any of the scoping criteria.

The staff verified that mechanical system evaluation boundaries were established for each system within the scope of license renewal. These boundaries were determined by mapping the pressure boundary associated with system-level license renewal intended functions onto the system flow and control drawings. Mechanical component types were loaded into a scoping and screening database and further review was performed to ensure that all component types were identified. A preparer and an independent reviewer performed a comprehensive evaluation of the boundary drawings to ensure the completeness and accuracy of the review results. Following identification of all system component types, the applicant used the license renewal boundary as an aid to evaluate each component against the scoping criteria of 10 CFR 54.4(a).

System components meeting the criteria of 10 CFR 54.4(a) were classified as within the scope of license renewal.

The staff conducted detailed discussions with the applicant’s license renewal project personnel and reviewed documentation pertinent to the scoping process. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and implementation procedures and whether the scoping results were consistent with CLB requirements.

The staff reviewed the process of scoping for the RHRSW and ECCW systems. The staff verified that the applicant had identified and highlighted system flow and control drawings to develop the system boundaries in accordance with the procedural guidance. The applicant was knowledgeable concerning the process and conventions for establishing boundaries as defined in the license renewal implementation procedures. Additionally, the staff verified that the applicant had independently verified the results in accordance with the governing procedures. Specifically, other personnel knowledgeable of the system had independently reviewed the marked-up drawings to ensure accurate identification of system intended functions. The staff performed additional cross-discipline verification and independent reviews of the resultant highlighted drawings before final approval of the scoping effort.

Conclusion. The staff determined that the applicant’s methodology was consistent with the description provided in LRA Section 2.1.4 and that the guidance contained in SRP-LR Section 2.1 was adequately implemented. On the basis 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 met the requirements of 10 CFR 54.4(a).

Structural Component Scoping. The applicant performed its structural scoping in accordance with the detailed methodology defined in 0-TI-457, “Civil Technical Evaluations for License Renewal,” Revision 2. The scoping procedure was used to evaluate SSCs to identify their functions and determine which are intended functions required for compliance with one or more criteria of 10 CFR 54.4(a)(1)-(3). Initial identification of BFN structures was accomplished by reviewing BFN drawing 0-10E21-series and/or Maintenance Rule documentation, 0-TI-346. For each structure, the applicant further reviewed the drawings and plant databases to identify specific structural components and features. The structural component intended functions for SCs within the scope of license renewal were identified based on the guidance provided in Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," NEI 95-10, and the SRP-LR. The procedure also described the source design documentation to be used for the evaluation of structures meeting the 10 CFR 54.4(a) criteria including the UFSAR, general design criteria (GDC) document, and other appropriate documents. For civil structures, the evaluation boundaries were determined by developing a complete description of each structure with respect to the intended functions performed by the structure and its components. A license renewal database was created for use in compiling the structural scoping results. The database contained (1) a unique identification number for each structure, (2) a list of structural components or commodity types associated with the structure, (3) evaluation results for each of the 10 CFR 54.4(a)(1)-(3) criteria for the structure, (4) a description of structural intended functions and source reference information for the functions, and (5) a reference to pertinent license renewal drawings associated with each structure.

License renewal procedure 0-TI-457 was also used to define the evaluation boundaries and discipline interfaces for civil/mechanical and civil/electrical systems. With respect to the civil/mechanical interface, the procedure identified the following component types within mechanical systems that were evaluated as part of the civil review. These component types included: (1) piping system supports, (2) HVAC duct supports, (3) equipment supports and foundations, (4) bolting and fasteners for structural supports and mechanical fasteners that are required for mechanical closure of mechanical components, and (5) whip restraints and jet impingement shields.

With respect to the civil/electrical interface, the procedure identified the following component types within electrical systems that were evaluated as part of the civil review. These component types included: (1) cable trays and supports, (2) conduits and supports, (3) electrical cabinets, panels, racks, and other enclosures providing structural integrity, (4) instrument racks, panels, frames, and enclosures providing structural integrity, and (5) electrical and I&C penetrations providing structural support functions.

The staff conducted detailed discussions with the applicant’s license renewal project personnel and reviewed documentation pertinent to the scoping process. The staff assessed whether the scoping methodology outlined in the LRA and implementation procedures were appropriately implemented and whether the scoping results were consistent with CLB requirements. The staff also reviewed several plant structural evaluation results for the reactor building and turbine building to verify proper implementation of the scoping process for structural components. The staff also compared a sample of structural components identified in the drawings to the structural list in the license renewal data base to ensure consistency. Based on these audit activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

Conclusion. The staff determined that the applicant’s methodology for structural scoping was consistent with the description provided in LRA Section 2.1.4.3 and the guidance contained in the SRP-LR Section 2.1. Based on a 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 concluded that the applicant’s methodology for identification of structural components within the scope of license renewal met the requirements of 10 CFR 54.4(a).

Electrical and I&C Scoping. The staff reviewed 0-TI-456, “Electrical Technical Evaluations For License Renewal,” which describes the electrical and I&C scoping and screening process and discussed the methodology and results with the applicant’s cognizant engineers. With the exception of components in the SBO offsite power restoration flow path, plant electrical and I&C components were evaluated using a “spaces” approach. The spaces approach identifies the electrical and I&C commodity groups that are installed in the plant and the limiting environmental conditions for each group. The spaces approach then determines if any area environment is more severe than the limiting environment for the commodity group. If the area environment is more severe than a commodity group’s limit, and if a component in the commodity group is actually located in the area, an AMR is required for that commodity group.

For this LRA, the applicant used a bounding spaces approach, as described in NEI 95-10. Electrical and I&C component types used plant-wide were identified without regard to the plant system they are in. The applicant used the listing provided by NEI 95-10, Appendix B as the basis for this list. Electrical component types were identified from the plant controlled computer database, EMPAC. Then these component types were assembled into commodity groups such as breakers, switches, and cables using the NEI 95-10, Appendix B list as a starting point. The EMPAC database has a fine division of component titles based on component performance characteristics, so sub-commodity groups were formed to separate components into specific groups with common applications or materials. Thus under the commodity group, “circuit breakers,” there may be a number of sub-commodity groups including all the circuit breakers identified in EMPAC as having common application, operating characteristics, fabrication materials, etc. The result is a detailed list by commodity and sub-commodity of all electrical and I&C components installed in the plant.

An exception to the spaces approach was the identification of electrical and I&C equipment needed for the SBO event offsite power restoration. Using the intended-function approach, the applicant developed license renewal drawings showing the basic electrical distribution paths for SBO offsite power restoration. Plant operating procedures were used to develop these SBO offsite power restoration license renewal drawings and to identify the components required to perform the function. The staff determined that the scoping and screening methodology used in 0-TI-456, “Electrical Technical Evaluations For License Renewal”; and described by the applicant’s engineers during the audit provided adequate guidance, was consistent with the requirements of 10 CFR 54.4 for the scoping evaluation of electrical components.

Conclusion. The staff determined that the applicant’s methodology for electrical and I&C scoping was consistent with the description provided in LRA Section 2.1.4.2 and the guidance contained in the SRP-LR. Based on review of information contained in the LRA, the applicant’s detailed scoping implementation procedures, and a sampling review of electrical component scoping results, the staff concluded that the applicant’s methodology for identification of electrical and I&C components within the scope of license renewal met the requirements of 10 CFR 54.4(a).

2.1.3.2 Screening Methodology

The staff reviewed the screening methodology used by the applicant to determine if mechanical, structural, and electrical components within the scope of license renewal would be subject to further aging management evaluation. The applicant described the screening methodology in LRA Section 2.1.5. In general, the applicant’s screening approach consisted of evaluations to determine which structures and components within the scope of LRA were passive and long-lived. Passive and long-lived structures and components were then subject to an AMR.

The staff evaluated the applicant’s screening methodology against criteria contained in 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2) using the review guidance contained in SRP-LR Section 2.1.3.2, “Screening.” The staff evaluation of the applicant’s screening approach for each of these disciplines is discussed below.

2.1.3.2.1 Mechanical Component Screening

The staff reviewed the methodology used by the applicant to determine if mechanical components within the scope of license renewal would be subject to further AMR. For mechanical components, the applicant applied a screening process to each mechanical system determined to be within the scope of license renewal in order to determine the types of mechanical component commodities within the systems and the various materials and environments to be considered in the AMR. The applicant then established evaluation boundaries for the various plant mechanical systems in order to further identify individual mechanical components for review.

The listing of mechanical components was facilitated by combining these items into commodity groups from a review of each boundary drawing. The applicant placed these commodity groups into the license renewal database and evaluated them in accordance with the screening criteria described in 0-TI-455. The applicant provided the staff with a detailed discussion of the process and provided screening report information from the license renewal database that described the screening methodology, as well as a sample of the screening results reports for a selected group of SR and NSR systems. The staff determined that the screening methodology was consistent with the requirements of the Rule and that implementation of the methodology will identify SCs that meet the screening criteria of 10 CFR 54.21(a)(1).

During the audit, the staff reviewed the methodology used by the applicant to identify and list the mechanical components and commodities subject to an AMR, as well as the applicant's technical justification for this methodology. The staff discussed the methodology and results with the applicant's cognizant engineers and senior staff. The staff also examined the applicant's results from the implementation of this methodology by reviewing a sample of the mechanical systems identified as within the scope of license renewal. These systems included the RHRSW system and EECW system. The review included the evaluation boundaries and resultant in-scope components, the corresponding component-level intended functions, and the resulting list of mechanical components and commodity groups subject to an AMR.

The staff reviewed several summary screening reports, which list a breakdown of the mechanical components that are within the scope of license renewal. Each report lists several categories, including component type, component material, whether an AMR is required, and an extensive comment section. The staff also reviewed a sample of the mechanical drawing packages assembled by the applicant and discussed the process and results with the cognizant engineers who performed the review. The staff did not identify any discrepancies between the methodology documented and the implementation results.

Conclusion. The staff determined that the applicant's mechanical component screening methodology was consistent with the guidance contained in the SRP-LR and was capable of identifying those 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 staff reviewed 0-TI-457, "Civil Technical Evaluations For License Renewal," which outlined the applicant's methodology to determine if SCs within the scope of license renewal would be subject to an AMR. The screening process applied to in-scope buildings and civil structures was designed to determine the structural elements and construction materials, as well as to determine the environments to which these buildings and civil structures will be exposed so that these factors could be considered in the AMR. Engineering document 0-TI-457 Section 6.3, "Structures Screening," describes the guidance for the structural screening process. For all structural component types with intended functions, the applicant then determines if the component type is long-lived. The applicant used existing plant program procedures and operating experience to determine if the component type was subject to replacement based on a qualified life or whether it was long-lived.

During the audit of the applicant's license renewal scoping and screening process, the staff reviewed the methodology used by the applicant to identify and list the structural components and structural commodities subject to an AMR as well as the applicant's technical justification for this methodology. The staff discussed the methodology and results with the applicant's cognizant engineers and senior staff. The applicant provided the staff with a detailed discussion of the process and provided technical reports that described the screening methodology as well as a sample of the screening results for a selected group of structures.

The staff also examined the applicant's results from the implementation of this methodology by reviewing a sample of the reactor building and turbine building plant structures identified as being within the scope of license renewal. The review included the evaluation boundaries and resultant in-scope components, the corresponding component-level intended functions, and the resulting list of structural components and structural commodity groups subject to an AMR.

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

2.1.3.2.3 Electrical Component Screening.

The staff reviewed the applicant's procedure 0-TI-456, "Electrical Technical Evaluations For License Renewal," which provided guidance on the screening of electrical and I&C components. The applicant used a bounding spaces approach as described in NEI 95-10, Revision 3, to perform the electrical evaluation. The electrical and I&C component types were identified from EMPAC. These component types were assembled into commodity groups such as breakers, switches, and cables using the NEI 95-10, Appendix B, list and supplemented with site-specific information. The applicant then applied the screening criteria to determine those electrical commodities subject to an AMR.

The staff discussed the methodology and results with the applicant's cognizant engineers and senior staff. The staff also examined the applicant's results from the implementation of this methodology by reviewing several electrical and I&C commodity reports and samples from the license renewal database. The review verified that the applicant's staff had consistently applied the screening criteria to identify those electrical and I&C commodity groups subject to an AMR. The staff determined that the electrical screening process was consistent with criteria in 10 CFR 54.21(a)(1)(ii) and excluded those components or commodity groups that are subject to equipment qualification requirements. The staff did not identify any discrepancies between the methodology documented and the implementation results.

The staff also reviewed the applicant's approach to scoping and screening of electrical fuse holders. In license renewal ISG-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," dated March 10, 2003, the staff stated that, consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders would be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This staff position applies only to fuse holders that are not part of a larger assembly, but support SR and NSR functions in which the failure of a fuse precludes a safety function from being accomplished (10 CFR Part 54.4(a)(1) and 10 CFR 54.4(a)(2)). As described in LRA Sections 2.1.8.5, and 3.6.2.3.1, the applicant developed a process for identifying and evaluating fuse holders as part of its license renewal evaluation. The process included using EMPAC to identify fuses in the plant and then to apply a series of evaluations and screening to identify a subset of the plant fuses which would potentially be susceptible to various effects of moisture or chemical contamination, thermal cycling, vibration, and mechanical stress. The applicant evaluated plant operating experience and determined that fatigue due to mechanical stress was an applicable aging effect/mechanism. The applicant then evaluated all remaining fuses to determine if any were susceptible to mechanical stress. The staff reviewed the applicant's process for identifying and evaluating the fuse holders and determined it was adequate.

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

2.1.4 Conclusion

The staff's review of the information presented in LRA Section 2.1, 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 formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology was consistent with the requirements of the Rule and the staff's position on the treatment of NSR SSCs.

On the basis of this review, the staff concluded that there is reasonable assurance that the applicant's methodology for identifying the SSCs within the scope of license renewal and the structures and components requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 Plant-Level Scoping Results

2.2.1 Introduction

In LRA Section 2.1, the applicant described the methodology for identifying the systems and structures (SSs) within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which of the SSs are required to be included within the scope of license renewal. The staff reviewed the plant-level SSs relied upon to mitigate DBEs, as required by 10 CFR 54.4(a)(1), or whose failure could prevent satisfactory accomplishment of any of the SR functions, as required by 10 CFR 54.4(a)(2), as well as the SSs relied on in safety analyses or plant evaluations to perform a function that is required by any of the regulations referenced in 10 CFR 54.4(a)(3).

2.2.2 Summary of Technical Information in the Application

In LRA Tables 2.2.1 and 2.2.2, the applicant provided a list of the plant systems and structures, respectively, identifying those that are within the scope of license renewal and those that are not within the scope of license renewal. Based on the DBEs considered in the plant's CLB, other CLB information relating to NSR systems and structures, and certain regulated events, the applicant identified those plant-level systems and structures that are within the scope of license renewal, as defined by 10 CFR 54.4.

2.2.3 Staff Evaluation

In LRA Section 2.1, the applicant described its methodology for identifying the systems and structures that are within the scope of license renewal and subject to an AMR. The staff reviewed the scoping and screening methodology and provided its evaluation in the safety evaluation report (SER) Section 2.1. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results, as shown in LRA Tables 2.2.1 and 2.2.2, and added systems due to the changed scoping methodologies to confirm that there were no omissions of plant-level systems and structures within the scope of license renewal.

In response to RAI 2.1-2A(3), described in SER Section 2.1, the applicant revised the methodology used to determine the NSR SSCs to be included in the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). The applicant’s response to RAI 2.1-2A(3) and supplemental information related to implementation of the revised scoping methodology are documented in the applicant’s response, dated February 28, 2005. As a result of the implementation of the scoping methodology changes, the applicant expanded the scope of license renewal and added the following mechanical systems that had additional in-scope piping or components:

- condensate and demineralized water system
- containment system
- reactor building closed cooling water system
- auxiliary decay heat removal system
- fuel pool cooling and cleanup system
- CO_2 system

- sampling and water quality system
- off-gas system
- radioactive waste treatment system
- diesel generator starting air system

The applicant also added the following structures to the scope of license renewal:

- radwaste building
- service building

In response to a follow-up question of RAI 2.1-2A(1), dated May 31, 2005, described in SER Section 2.1, the applicant provided supplemental information on the implementation of the revised scoping methodology of NSR piping segments that support secondary containment penetrations qualified to seismic Class II pressure retention requirements.

As a result of the implementation of the scoping methodology changes, the applicant added the following mechanical systems that had additional piping or components added to the scope of license renewal:

The following mechanical systems only had systems boundary changes. No new component types, materials, or environments that affected either the scoping/screening or AMR results in the LRA were added.

- main steam system
- auxiliary boiler system
- raw cooling water system
- station drainage system
- high pressure coolant injection system
- residual heat removal system
- radioactive waste system
- fuel pool cooling and cleanup system
- radiation monitoring system

The following mechanical systems had systems boundary changes. For some of these systems, new component types were added that affected the scoping/screening results in the LRA. For all systems listed, new components, materials or environments that affected the AMR results in the LRA were added.

- condensate and demineralized water system
- feedwater system
- potable water system
- service air
- containment system

The remainder of the mechanical systems were not affected by this review.

The staff reviewed the selected systems and structures that the applicant had not identified as falling within the scope of license renewal to verify whether the systems and structures have any intended functions that would require their inclusion within the scope of license renewal in accordance with 10 CFR 54.4. The staff's review of the applicant's implementation was conducted in accordance with the guidance described in SRP-LR Section 2.2, "Plant-Level Scoping Results."

The staff sampled the contents of the UFSAR based on the systems and structures listed in LRA Tables 2.2.1 and 2.2.2 to determine whether there are any systems or structures that may have intended functions within the scope of license renewal, as defined by 10 CFR 54.4, but were omitted from within the scope of license renewal. The staff did not identify any omissions.

2.2.4 Conclusion

The staff reviewed LRA Section 2.2 and the supporting information in the UFSAR to determine whether any systems and structures within the scope of license renewal had not been identified by the applicant. The staff's review did not identify any omissions. On the basis of this review, the staff concluded that the applicant had properly identified the systems and structures that are within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 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 systems
- engineered safety features
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived structural SSCs that are within the scope of license renewal and subject to an AMR. To verify whether the applicant has properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there were no omissions of mechanical system components that meet the scoping criteria and are subject to an AMR.

In the LRA, the applicant described a methodology for mechanical systems scoping and screening that interprets 10 CFR 54.21(a) differently from previous LRAs and the SRP-LR. Specifically, the applicant did not define component-level scoping boundary. The applicant combined passive, long-lived, and intended function criteria into one screening process to meet the requirements of 10 CFR 54.21(a)(1). The applicant highlighted those components on the license renewal drawings that are passive, long-lived, and have intended functions as being subject to an AMR. Therefore, some of the components that have intended functions may not be identified and listed in the LRA Section 2.3 tables or highlighted on the license renewal drawings, because the component scoping boundary is not defined.

The methodology used by previous LRA applicants, consistent with the SRP-LR review guidance, describes two steps to perform scoping and screening. The first step, scoping, identifies those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a). The applicant then identified the components of the in-scope system that have intended functions to be included in the license renewal scope in accordance with the criteria of 10 CFR 54.4(a). The component scoping boundary within a system is then highlighted on license renewal drawings. The second step, screening, identifies those components in the scoping boundary that are passive and long-lived in accordance with 10 CFR 54.21(a)(1). The resulting components from these scoping and screening steps are subject to an AMR. This matter was further complicated because the drawings for Unit 1 only highlighted those portions of the system that are subject to an AMR and are not expected to change as a result of modifications needed to bring the CLB for Unit 1 in line with Units 2 and 3.

Because the applicant used a different scoping and screening process and provided insufficient information in its LRA associated with this methodology, the staff was unable to determine whether there were any omissions of components from the scope of license renewal and subject to an AMR. The applicant did not provide scoping information at the component level equivalent to that provided by previous LRA applicants for the review of systems in LRA Section 2.3.

To better understand the applicant's scoping methodology, the staff conducted an audit review at the TVA offices in Chattanooga, TN, between June 7 and 10, 2004, to review the applicant's license renewal project guidelines and procedures. The purpose of this plant audit was to determine, by review of plant information, that system components within the scope of license renewal are identified and that the components of the in-scope systems subject to an AMR are screened. The staff reviewed the applicant's site documentation in the following areas:

- department procedure for license renewal technical evaluations
- mechanical technical evaluations for license renewal
- SBO calculations
- system reports

To ensure that all components of an in-scope system were screened, or identified as passive and long-lived in accordance with 10 CFR 54.21(a)(1), the staff audited the system report for the main steam system. Additionally, the staff reviewed the SBO calculations to determine if any systems were omitted from scope in accordance with 10 CFR 54.4(a)(3). In its trip report, the staff documented which procedures and reports were reviewed at the plant site.

As a result of the staff's review of LRA Section 2.3, the staff found that additional clarification was needed to determine whether the applicant's mechanical component-level scoping for the in-scope systems was adequate. Therefore, by letter dated August 31, 2004, the staff issued RAIs to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a). The following paragraphs describe the staff's RAIs and the applicant's responses.

In RAI 2.3-1, the staff stated that many of the tables in LRA Section 2.3 list "fittings" as a component type subject to an AMR. The term "fittings" typically refers to components such as elbows, tees, unions, reducers, caps, flanges, etc., which are an integral part of piping systems. LRA Section 2.3.5 lists other components that fall under the component type "fittings" but does not list the above components. Therefore, the staff requested the applicant to confirm that components such as those listed above are considered as part of the component type "fittings" in the LRA tables, or to state if they are considered as part of another listed component type.

In its response, by letter October 19, 2004, the applicant stated that elbows, tees, unions, reducers, caps, flanges, etc., are not typically shown with UNIDs on the license renewal drawings, and that they were not listed in LRA Section 2.3.5. LRA Section 2.3.5 was generated to help identify components that are shown on boundary drawings, have a specific UNID, and are included in a commodity. The applicant further stated that components such as elbows, tees, unions, reducers, caps, flanges, quick disconnects, thermal sleeves, aux heads, and drains are included in commodity type "fittings."

Based on its review, the staff found the applicant's response to RAI 2.3.-1 acceptable. It confirms that the components addressed in the RAI are already included in the component type "fittings" as being subject to an AMR. Therefore, the staff's concern described in RAI 2.3-1 is resolved.

In RAI 2.3-2, the staff stated that LRA Section 2.1.7.9, Group (c) states that "oil, grease, and component filters" are short-lived and are periodically replaced. It further states that various plant procedures are used in the replacement of oil, grease, and component filters that are within the scope of license renewal. In the process of verifying the results of the above applicant's methodology, the staff raised the following questions.

Because the LRA uses AMR boundary drawings instead of scoping boundary drawings, the components that are within the scope of license renewal but not subject to an AMR are not highlighted on the drawings. Therefore, the staff was unable to determine, for mechanical systems, whether all in-scope oil, grease, and component filters had been identified in accordance with 10 CFR 54.4. Additionally, the staff could not determine whether plant procedures exist and are adequate for the all in-scope "oil, grease, and component filters" that are not subject to an AMR. For example, "crane system" is within the scope of license renewal in accordance with 10 CFR 54.21(a)(2); however, filters of the system are not listed in LRA Table 2.3.3.34 as component types subject to an AMR. Additionally, no drawings were provided for this system. The staff could not determine whether this system contains any in-scope oil, grease, and component filters, or whether the plant procedures are adequate for them. Therefore, in RAI 2.3-2, the staff requested the applicant to do the following:

1. Verify all the in-scope oil, grease, and component filters that are identified in the license renewal boundary drawings. If not, list those in-scope oil, grease, and component filters that are not identified in the drawings.
2. Identify the plant procedures that are used for the replacement of every in-scope oil, grease, and filter that is not subject to an AMR to demonstrate that the oil, grease, or filter is replaced on a periodic basis and identify the specific period.
3. Identify those in-scope oil, grease, and component filters without proper plant procedures that are subject to an AMR.

In its response, by letter October 19, 2004, the applicant stated:

> 1. The boundary drawings were not intended to depict oil or grease. All filters associated with mechanical systems are not depicted on boundary drawings. The boundary drawings are based on flow diagrams which depict components in the system fluid flow path (i.e., pressure boundary). Even though most discrete components are shown on the flow diagrams, the flow diagrams show various levels of detail associated with vendor supplied skids. For example, some flow diagrams associated with vendor supplied skids show the associated lubricating oil and cooling water components (i.e., filters, pumps, etc.). Other flow diagrams may only depict the major component in the flow path, such as a heat exchanger associated with a vendor supplied chiller package. The refrigerant loop associated with the vendor supplied chiller unit is not depicted on the flow diagram. Vendor drawings and vendor manuals provide details associated with the vendor supplied equipment. In these cases, the vendor documents were utilized to identify components, such as filters, that are subject to aging management review. Examples of filters that were subject to an AMR that were not shown on drawings are: Unit 1 reactor core isolation cooling system lube oil filters; Unit 1 high pressure coolant injection system lube oil filters; and filters

associated with the refrigerant loop of heating ventilation and air condition system chillers.

2. Browns Ferry has various maintenance procedures and work orders in place to assure that filters for safety related components are being monitored and replaced as required to assure that equipment will perform its function. Some examples of procedures used to replace the elements are: MPI-0-026-INS002 which is performed annually or 250 hour cumulative inspection, MPI-0-82-INS002 which performs the Standby Diesel Engine 24 month inspection, procedure 0-GI-300-1 Attachment 15.11 which is the Monthly Ventilation Filter Check, repetitive work orders done every 24 weeks, 0-SI-4.8.B.2-1 which is performed weekly, MPI-0-071-TRB001 and repetitive work order every 24 months, and MPI-0-073-TRB001 and repetitive work order every 12 weeks. Browns Ferry has various preventive maintenance procedures and work orders in place to assure that oil and grease for safety related components are being monitored and replaced as required to assure that equipment will perform its function. The following are examples of procedures that are used for oil and grease replacement: QMDS NUMBER MOV-001 (performed every 54 months), QMDS NUMBER MOV-002 (performed every 54 months), QMDS NUMBER MOV-003 (performed every 54 months), QMDS NUMBER MOT-001 (perform oil samples every six months), QMDS NUMBER MOT-003 (performed at 24 and 36 month intervals), QMDS NUMBER PLN-003 (performed every 3 years), EPI-0-000-MOT- 001 (Preventive Maintenance work orders are generated at various frequencies to add grease to motors), EPI-0-000- MOT-002 (Preventive Maintenance work orders are generated at various frequencies to add oil to motors), and MPI-0- 000-LUB001 (Preventive Maintenance work orders are generated at various frequencies to add grease to equipment). In addition, some components lubricants are monitored and replaced based on oil analysis (predictive maintenance).

3. Our review did not identify any cases where oil, grease, or in scope filters were without proper plant procedures to exclude them as short lived.

In the initial response review, the staff was unable to find the applicant's response to RAI 2.3-2 acceptable. The applicant did not provide sufficient information to provide reasonable assurance that all oil, grease and component filters are either outside the scope of license renewal or are replaced based on a qualified life or specified time period. By letter dated May 18, 2005, the applicant revised its response to state that it has various maintenance procedures and work orders in place to assure that all filters for SR components are being monitored and replaced as required to assure that the equipment will perform its function.

Based on its review, the staff found the applicant's revised response acceptable. There is reasonable assurance that all filters for SR components are covered by procedures or work orders. Therefore, the staff's concerns described in RAI 2.3-2 are resolved.

In RAI 2.3-3, the staff stated that LRA Section 2.1.7.2 states that insulation at BFN does not have an intended function associated with the scoping requirements of 10 CFR 54.4(a)(1) through (a)(3). However, there is insufficient information in the LRA and the UFSAR for the staff to determine if the statement is valid at such a generic level. Insulation may be required for a variety of reasons, e.g., systems efficiency, heat-load calculations, EQ purposes. etc. If the insulation is relied upon for EQ purposes, the passive, long-lived insulation should be within the scope of license renewal and subject to an AMR. Therefore, the staff requested that the applicant provide a basis for not including any piping or equipment insulation within the scope of license renewal.

On March 22, 2005, the staff held a teleconference with the applicant to discuss the treatment of insulation. In its response, by letter May 18, 2005, as modified by letter dated June 15, 2005, the applicant stated that all the mechanical piping and equipment insulation contained in the SR structures as well as some NSR structures have been added to the scope of license renewal, since they meet the criteria of 10 CFR 54.4(a)(2) and (a)(3). Piping and equipment insulation has the intended functions of insulate and integrity. The applicant stated that these intended functions will be added to LRA Table 2.0.1. The applicant also stated that piping and equipment insulation and insulation jacketing are component types that are subject to an AMR. LRA Table 2.1.7.2 will be added to reflect these two component types and their intended functions.

Based on its review, the staff found the applicant's response to RAI 2.3-3 acceptable. The applicant placed all piping and equipment insulation that is within SR and some NSR structures within the scope of license renewal and the insulation is subject to an AMR. Therefore, the staff's concern described in RAI 2.3-s3 is resolved.

The staff reviewed LRA Section 2.3 and the applicant's responses to the RAIs and performed a plant audit. Based on this review, the staff found that the applicant's methodology for scoping and screening was well documented in an auditable and retrievable form at the plant site. The staff also found that the results of the audit on the system and the regulated event confirmed that there were no omissions of any components subject to an AMR for the audited systems. In the LRA Section 2.3 tables, the staff found that the results are consistent with the methodology and are acceptable. With the additional information obtained from responses to RAIs 2.3-2 and 2.3-3, the staff concluded that the applicant, while using a different methodology from that described in the review guidance of the SRP-LR, provided scoping and screening results and components subject to an AMR with no omissions. For other in-scope systems that were not audited at the plant site, the staff issued RAIs related to components that could be subject to an AMR based on its review of the LRA, UFSAR, and site documentation.

In RAIs 2.1-2A(1) and (2) (described in SER Section 2.1) of the July 30, 2004, letter, the staff requested that the applicant describe the criteria used to determine that the integrity of in-scope piping functions (in the reactor building) is preserved if a potential age-related degradation failure occurred on the attached NSR piping (in the turbine building), given that the NSR piping is not in scope and piping is not anchored, and 2) explain how it determined that the SR piping (in the reactor building) is supported so that it would remain functional if a potential age-related degradation occurred on the NSR piping (in the turbine building) attached to it. In its response dated, October 18, 2004, the applicant committed to review the CLB requirements and identify the piping, supports and other components outside secondary containment required to maintain the structural integrity of the secondary containment. The applicant committed to performing this review prior to the period of extended operation. The deferral of this issue until prior to the period of extended operation is unacceptable. Therefore, the applicant performed the review, the results of which are documented in a letter dated May 31, 2005. The following mechanical systems only had systems boundary changes (i.e., no new component types, materials, or environments were added) that affected either the scoping/screening or AMR review results in the LRA:

- main steam system
- auxiliary boiler system
- raw cooling water system
- station drainage system
- high pressure coolant injection system
- residual heat removal system
- radioactive waste system
- fuel pool cooling and cleanup system
- radiation monitoring system

The following mechanical systems had systems boundary changes; however, for some of these systems, new component types were added that affected the scoping/screening results in the LRA. For all systems listed, new components, materials, or environments were added that affected the AMR review results in the LRA:

- condensate and demineralized water system
- feedwater system
- potable water system
- service air system
- containment system

The effects of these changes are evaluated and discussed in the corresponding sections of the SER.

In RAI 2.1-2A(3), described in SER Section 2.1, dated July 30, 2004, the staff requested that the applicant describe how the scoping and screening methodology ensured that NSR piping up to the first equivalent anchor point was included within the scope of license renewal. The applicant in its initial response to RAI 2.1.2A(3), dated September 3, 2004, committed to review the seismic Class I piping boundaries and identify any additional piping segments and supports/equivalent anchors that were needed to be placed within the scope of license renewal.

On September 24, 2004, in a teleconference between the staff and the applicant, the staff requested that the applicant provide additional information related to the methodology to be utilized to ensure the liquid-filled NSR piping up to the first equivalent anchor point was captured. By letter, dated January 31, 2005, the applicant stated that an extensive review was performed that included verification of each seismic Class I boundary that typically falls into one of the following categories: base-mounted equipment, pipe anchor, embedded piping segment, large run line, piping free end, flexible connection and overlap regions. Any identified piping, supports/equivalent anchors, or other components would be added to the scope of license renewal as needed.

In a letter dated February 28, 2005, the applicant provided final status information and results from the calculation review requested by the staff. In enclosure 1 of the letter, the applicant provided a summary of the following changes to the LRA as a result of this review.

The mechanical systems listed below had additional piping or components added to the scope of license renewal; however, even for those systems that had boundary changes as a result of the additional piping and components, no changes to the LRA were required, because the component-material-environment-program combination was already addressed in the LRA.

- condensate and demineralized water system
- standby liquid control system
- containment system
- reactor building closed cooling water system
- auxiliary decay heat removal system
- fuel pool cooling and cleanup system

The following mechanical systems also had additional piping or components added to the scope of license renewal. However, for these systems with boundary changes because of the addition of piping and components, changes to the LRA were required, because the component-material-environment-program combination was not addressed in the LRA.

- CO_2 system
- sampling and water quality system
- off-gas system
- radioactive waste treatment system
- diesel generator starting air system

The effect of these changes are evaluated and discussed in the corresponding sections of the SER (see Section 2.3.4.4 for details of RAIs 2.3.4.4-1 and 2.3.4.4-2).

2.3.1 Reactor Coolant Systems

In LRA Section 2.3.1, the applicant identified the structures and components of the reactor coolant systems (RCSs) that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the RCSs in the following sections of the LRA:

- 2.3.1.1 reactor vessel
- 2.3.1.2 reactor vessel internals
- 2.3.1.3 reactor vessel vents and drains system
- 2.3.1.4 reactor recirculation system

The corresponding SER subsections, 2.3.1.1 - 2.3.1.4, present the staff's review findings.

2.3.1.1 Reactor Vessel

2.3.1.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.1, the applicant described the reactor vessel. The reactor vessel provides a container for the reactor core and the primary coolant in which the core is submerged. Each unit has a separate reactor vessel. The reactor vessel is a pressure vessel with the geometry of a vertically-aligned cylinder capped with hemispherical heads of welded construction. The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated from low-alloy carbon steel plate that is clad on the interior with weld overlay. The cylindrical shell is clad with stainless steel and the bottom hemispherical head is clad with Inconel. The vessel top head is not clad and is secured to the reactor vessel by studs and nuts. The vessel flanges are sealed by two concentric metallic seal-rings that are designed for no detectable leakage through the inner or outer seal at any operating condition.

The reactor vessel contains SR components that are relied upon to remain functional during, and following, DBEs to ensure the following intended functions:

- forms part of the reactor coolant pressure boundary
- provides physical support for the reactor core and the reactor vessel internals
- ensures a floodable volume and coolant distribution to mitigate accidents
- provides pressure boundary
- provides structural support

In LRA Table 2.3.1.1, the applicant identified the following reactor vessel component types that are within the scope of license renewal and subject to an AMR: attachments and welds, closure studs and nuts, heads, flanges, shell, nozzle safe ends, nozzles, other external attachments, penetrations, refueling bellows support skirt, stabilizer bracket, and support skirt and attachment welds.

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 and the UFSAR Section 4.2, 7.8, and Appendices J, K, and L using the evaluation methodology described in SER Section 2.3. The staff conducted its review on the reactor vessel in accordance with the guidance described in SRP-LR Section 2.3, “Scoping and Screening Results - Mechanical Systems.”

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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.1.1.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor vessel components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor vessel components 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 LRA Section 2.3.1.2, the applicant described the reactor vessel internals. The reactor vessel internals are unique to each unit and provide partitions between regions within the reactor vessel in order to provide proper coolant distribution, thereby allowing power operation without fuel damage due to inadequate cooling. The reactor vessel internals also provide positioning and support for the fuel assemblies, control rods, in-core flux monitors, and other components to assure that control rod movement is not impaired. In addition, the reactor vessel internals provide a floodable volume so that the core can be adequately cooled if there is an external reactor vessel breach in the nuclear system process barrier.

The reactor vessel internals consist of the following components:

- core shroud
- shroud head and steam separator assembly
- core support
- top guide
- fuel support pieces
- control rod guide tubes (control rod housing)
- jet pump assemblies
- steam dryers
- feed water spargers
- core spray lines and spargers
- vessel head spray nozzle
- differential pressure and liquid control line
- in-core flux monitor guide tubes
- startup neutron sources
- surveillance sample holders

The reactor vessel contains SR components that are relied upon to remain functional during, and following, DBEs to ensure the following intended functions:

- provides physical support for the reactor core and the reactor vessel internals
- ensures a floodable volume and coolant distribution to mitigate accidents
- provides pressure boundary
- provides spray pattern
- provides structural support

In LRA Table 2.3.1.2, the applicant identified the following reactor vessel internals component types that are within the scope of license renewal and subject to an AMR: core shroud and plate; core spray lines and spargers; control rod drive (CRD) housing; dry tubes and guide tubes; fuel support; jet pump assemblies; and top guide.

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.2 and UFSAR Section 3.3, 4.2, and Appendices J, K, and L using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results.

In RAI 2.3.1.2-1, dated October 8, 2004, the staff requested the applicant to determine whether the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1) had been properly applied. The staff requested the following:

> In LRA Table 2.3.1.2, one of the intended functions of core spray spargers was appropriately identified as maintaining the spray pattern in a manner that all fuel assemblies will be adequately cooled following a loss of coolant accident (LOCA). The staff's understanding is that adequate long-term core cooling following a LOCA can only be assured by retaining the original spray distribution over the core, which was assumed for the CLB. In the SER for the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-18 report, the staff had concluded that, when performing inspection of core spray spargers, all boiling water reactor (BWR) plants must be treated as geometry-critical plants. Furthermore, it is staff's understanding that the previous BWRVIP designations of "geometry-tolerant" plants have been rescinded and all plants are now considered to be "geometry-critical." Consequently, in order to assure adequate cooling of the uncovered upper third of the core, the core spray system must provide adequate spray distribution to all assemblies in the core. The staff also believes that leakage through sparger and piping cracks, as well as repairs and potential blockage of spray nozzles must be considered in assessing the core spray distribution. As a result, it is essential that spraying water on the fuel assemblies in a pattern that was originally designed must be maintained, and that the applicant's aging management activities provide reasonable assurance that the original spray distribution will be preserved during the period of extended operation.
>
> On the basis of the above discussion, the staff requests the applicant to affirm that when performing inspection of core spray spargers, the BFN plants are inspected in accordance to the requirements for the "geometry-critical" plants, as required by the staff SER for the BWRVIP-18 report; and that the original spray pattern assumed for the CLB will be preserved during the extended period of operation.

In its response, by letter dated November 3, 2004, the applicant stated that BFN is performing inspections as required by the BWRVIP-18 report, as modified by January 11, 1999, letter, which requires that core spray spargers of all plants receive the same type of inspection. The applicant also stated that, based on the Chemistry Control Program and that the nozzles are constructed of a stainless steel material, corrosion is not a credible aging mechanism to cause flow blockage.

Based on its review, the staff found the applicant's response to RAI 2.3.1.2-1 acceptable. The applicant included the subject components and their intended functions as within scope requiring an AMR. Therefore, the staff's concern described in RAI 2.3.1.2-1 is resolved.

Recent industry experience of steam dryer failures at operating BWRs and the potential of steam dryers to generate loose parts that can degrade SR components have necessitated that the staff reconsider whether steam dryers should be within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and require aging management. Although the steam dryer does not perform an SR function, the steam dryer must maintain its structural integrity to support emergency core cooling system (ECCS) operation, and also to prevent the occurrence of loose parts in the reactor vessel or steam lines that could adversely affect plant operation.

In RAI 2.3.1.2-2, dated October 8, 2004, the staff requested the applicant to provide the following additional information:

- Whether the steam dryer designs at BFN and Quad Cities are similar. If not, the applicant was requested to describe the significant differences between the two designs that support the conclusion that steam dryer failures similar to those that occurred at Quad Cities are unlikely to develop at the BFN steam dryers following power uprate.
- Describe any actions, including analysis, that will be performed to confirm that extended power uprate[1] conditions will not generate loose parts from the steam dryer.

In its response, by letter November 3, 2004, the applicant stated that the steam dryers had been added within the scope of license renewal on the basis of 10 CFR 54.4(a)(2) scoping criterion. In addition, the applicant provided the following information to compare the configuration of the steam dryers at BFN with the configuration of the steam dryers at the Quad Cities Nuclear Power Station plants.

> There are three general types of steam dryer configurations:
>
> 1. BWR/3-style steam dryers with a square hood and internal braces (This is the configuration at Quad Cities).
> 2. BWR/4-style steam dryers that have slanted hoods (This is the configuration at BFN).

[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

3. BWR/5 and later steam dryer designs that incorporate curved hoods to optimize the steam flow.

Basically the BFN dryer is a slanted hood design, which is much less susceptible to vibration-induced failures than the square hood design of the Quad Cities dryers. General Electric Corporation (GE) has conducted finite element model analysis, which documents that the square hood is more susceptible to operating stresses. The forcing function for the dryer loads has been identified as being primarily acoustic loads that originate in the steam lines. The BWRVIP and the industry have efforts underway to develop methods to measure and document the amount of additional loads that may be placed on the dryer as the result of uprated conditions. The applicant further stated that it will follow the BWRVIP guidelines for the inspection and evaluation of the dryers to insure their future integrity under uprated operating conditions.

The applicant added the subject components within the scope requiring an AMR and the staff's concerns described in RAI 2.3.1.2-2 are partly resolved. However, the subject of the second question of the staff RAI is currently being reviewed as part of the ongoing EPU review (see footnote previous page).

2.3.1.2.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor vessel internals components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor vessel internals components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Vents and Drains System

2.3.1.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.3, the applicant described the reactor vessel vents and drains system. The reactor vessel vents and drains system consists of the valves and piping connected to the reactor coolant pressure boundary (RCPB). This includes the reactor vessel head vent piping, the reactor vessel bottom head drain piping, and the blowdown piping from the main steam relief valves (MSRVs) to the pressure suppression chamber. The system is unique to each unit and shares no components with other units. All piping and components are located within the primary containment.

The reactor vessel vents and drains system contains SR components that are relied upon to remain functional during, and following, DBEs to ensure the following intended functions:

- provides a path for the main steam (MS) system, safety relief valves (SRVs), and steam blowdown to the primary containment suppression pool
- provides RCPB

- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.1.3, the applicant identified the following reactor vessel vents and drains system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, piping, RCPB piping, valves, and RCPB valves.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 and UFSAR Sections 4.11, 7.8, and C.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.1.3.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor vessel vents and drains system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor vessel vents and drains system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Reactor Recirculation System

2.3.1.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.4, the applicant described the reactor recirculation system. The reactor recirculation system is unique to each unit and consists of two piping loops connected to, but external to, the reactor vessel. Each loop has a single, variable speed, motor driven pump with pump suction and discharge valves. Each pump takes suction from the reactor vessel downcomer region and discharges into a manifold that supplies flow to ten jet pumps contained within the reactor vessel. During normal operations, the system provides sufficient subcooled water to the reactor core to maintain the normal core operating temperatures. The system also provides control of reactor power by varying recirculation flow during normal operations. In addition, the system provides a flow path for the low pressure coolant injection flow from the

RHR system to the reactor vessel during design basis accidents (DBAs) and a flow path to and from the RHR system for removal of decay heat at low temperatures.

The reactor recirculation system contains SR components that are relied upon to remain functional during, and following DBEs. The failure of NSR SSCs in the reactor recirculation system could prevent the satisfactory accomplishment of an SR function. In addition, the reactor recirculation system performs functions that support fire protection, EQ, and ATWS.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides a primary containment boundary
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.1.4, the applicant identified the following reactor recirculation system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, flexible connectors, heat exchangers, piping, RCPB piping, pumps, reactor coolant pumps, restricting orifices, RCPB restricting orifices, strainers, tanks, tubing, valves, and RCPB valves.

2.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 and UFSAR Sections 3.7.6, 4.3, 5.2.3, 7.8, 7.9, and 7.19 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.1.4, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant’s scoping and screening results. The staff requested the applicant to determine whether the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1) have been properly applied.

In RAI 2.3.1.4-1, dated October 8, 2004, the staff stated that in LRA Table 2.3.1.4, for the reactor recirculation system, and for other systems, for example, the containment inerting system, heat exchangers have been identified as a component type within the scope of license renewal. However, for these heat exchangers, the pressure boundary function was identified as the only intended function requiring aging management. Therefore, the staff requested the applicant to clarify why the heat transfer function was not also identified as an intended function that needs to be maintained during the extended period of operation by assigning appropriate aging management program (AMP) for it.

In its response, by letter dated November 3, 2004, the applicant stated that the heat exchangers associated with LRA Table 2.3.1.4 are the heat exchangers shown on license renewal drawings 2-47E844-2-LR and 3-47E817-2-LR. The shell sides of these heat exchangers are within the scope of license renewal for secondary containment as a pressure boundary for the raw water system. These heat exchangers are not SR, but the tube side is within the scope of license renewal to satisfy 10 CFR 54.4(a)(2) requirements only. Therefore, these heat exchangers are not credited for their heat transfer function.

Based on its review, the staff found the applicant's response to RAI 2.3.1.4-1 acceptable. The applicant provided the justification as to why the heat transfer function of the subject components need not be within the scope of license renewal requiring aging management. Therefore, the staff's concern described in RAI 2.3.1.4-1 is resolved.

2.3.1.4.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor recirculation system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor recirculation system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

In LRA Section 2.3.2, the applicant identified the structures and components of the engineered safety features (ESFs) that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the ESF in the following sections of the LRA:

- 2.3.2.1 containment systems
- 2.3.2.2 standby gas treatment system
- 2.3.2.3 high pressure coolant injection system
- 2.3.2.4 residual heat removal system
- 2.3.2.5 core spray system
- 2.3.2.6 containment inerting system
- 2.3.2.7 containment atmosphere dilution system

The corresponding SER subsections, 2.3.2.1 – 2.3.2.7, present the staff's review findings with respect to the ESF for BFN.

2.3.2.1 Containment System

2.3.2.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.1, the applicant described the containment system. The containment system includes the following subsystems: the primary containment and primary containment isolation system, the secondary containment, and the reactor building ventilation system. The scoping and screening results for the primary containment isolation valves for the various processes are presented within their respective systems. The results of the scoping and screening evaluations for the other components within the containment system including valves, piping, penetrations, structural steel, that are essential for primary containment integrity, are presented in other sections of this SER.

The primary containment system for each unit employs an independent pressure suppression that houses the reactor vessel, reactor coolant recirculation loops, and other branch connections of systems that form the RCPB. The Mark I containment is a pressure suppression system design, which consists of a drywell and a pressure suppression chamber that is alternatively referred to as the “torus” or “wetwell.” The Mark I pressure suppression system also contains a connecting vent system between the drywell and the pressure suppression chamber, isolation valves, equipment for establishing and maintaining a pressure differential between the drywell and pressure suppression chamber, and other service equipment. Air that is transferred to the pressure suppression chamber pressurizes the chamber and is subsequently vented to the drywell to equalize the pressure between the two vessels, and it is necessary in the event of a process system piping failure within the drywell. Cooling systems are provided to remove heat from the drywell and the water from the pressure suppression chamber, thus cooling and controlling the pressure in the primary containment under accident conditions. In addition, valves and flowpaths are provided to control the internal and the torus/drywell differential pressure. If long-term, post-accident cooling capability is lost, resulting in a pressure increase that would jeopardize the structural integrity of the primary containment, a hardened wetwell vent to the plant stack can be opened to relieve the pressure increase.

The containment system also includes the secondary containment system. The secondary containment system provides an essentially leak-tight envelope for any radiation release from the primary containment during DBEs. The secondary containment system also provides a primary envelope for radiation releases when the primary containment systems are open for refueling or maintenance.

This structure is divided into three reactor zones and a refueling zone. Each reactor zone houses the reactor, the primary containment, and the individual unit’s ECCS. The structure also contains a spent fuel storage pool for each individual unit. The refueling zone allows continuous access to the three spent fuel storage pools and the reactor vessel for refueling and servicing.

The reactor building ventilation system is also included within the containment system. The reactor building is heated, cooled, and ventilated during normal and shutdown operations by a circulating air system. The reactor building ventilation system is shut down and isolated when a zone of secondary containment is isolated and connected to the standby gas treatment (SGT) system. The ventilation system has supply fans that provide makeup air that is filtered, heated by hot water coils for winter heating, and cooled by evaporative coolers for summer cooling. Air is exhausted from the reactor building by exhaust fans located on the building's roof. Air from each zone is monitored before release. The reactor building ventilation system also includes area cooling units for areas containing ECCS components.

The containment system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the containment system could prevent the satisfactory accomplishment of an SR function. In addition, the containment system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a primary containment boundary
- provides a vacuum relief system (vacuum breaker valves) to prevent drywell or suppression chamber (torus) negative pressure from damaging the containment structure
- provides air-operated re-closure of the inboard reactor building to the torus vacuum breakers
- provides pressure suppression by cooling/condensation of the safety relief valves (SRVs) steam from boiler drains and vents system and reactor core isolation cooling (RCIC) system and high pressure coolant injection (HPCI) system turbine exhaust steam
- accepts HPCI and RCIC system pump minimum bypass flow
- provides a water supply to the RCIC system, HPCI system, core spray (CS) system, and RHR system pumps
- provides forced air cooling for the RHR system and the CS system pump motors
- provides a secondary containment boundary (passive functions)
- provides a pressure boundary of containment system components connected to the control air system that must maintain the pressure boundary in support of supplying containment atmosphere dilution (CAD) to the main steam safety relief valves (MSRVs)
- provides fire dampers that are required for unit operation
- provides debris protection
- provides fire barrier
- provides for heat transfer
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.1, the applicant identified the following containment system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, heat exchangers, fire dampers, flexible connectors, fittings, piping, strainers, traps, tubing, and valves.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1, LRA Appendix F, and UFSAR Sections 5.2, 5.3, 5.3.3.2, 5.3.3.6, and 7.3, F.7.1, and F.7.11 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.2.1, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.2.1-1, the staff requested that the applicant clarify whether all the system components such as, but not limited to, air cooling unit housings, dampers and damper housings, cooling coil housings, valve bodies, and screens for intake and exhaust structures are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated November 3, 2004, and supplemented by a letter dated December 3, 2004, the applicant stated that all applicable system components consisting of air cooling unit housings, dampers and damper housings, cooling coil housings, and valve bodies are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1) for the RBVS (containment). LRA Section 2.3.5, "Notes Associated with the Section 2.3 Tables," is revised to reflect these component types and, therefore, is part of "Component Types" in LRA Table 2.3.2.1, "Containment System," and LRA Table 3.2.2.1, "Containment System-Summary of Aging Management Evaluation." The applicant also stated that the RBVS contains an intake plenum that contains louvers with screens and that these components perform no license renewal function; therefore, these components are not within the scope of license renewal.

Based on the review, the staff found the applicant's response to RAI 2.3.2.1-1 acceptable. The applicant clarified that all applicable system components consisting of air cooling unit housings, dampers and damper housings, cooling coil housings, and valve bodies are within the scope of license renewal, and subject to an AMR for the RBVS and are already included in "Component Types" in LRA Tables 2.3.2.1 and 3.2.2.1. Since the RBVS intake plenum with louvers and screens performs no license renewal function, these components are not within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.2.1-1 is resolved.

2.3.2.1.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the containment system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the containment system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Standby Gas Treatment System

2.3.2.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.2, the applicant described the SGT system. The SGT system is shared between Units 1, 2, and 3. The SGT system consists of a suction duct system, three filter trains and blowers, and a discharge vent system. The common suction duct system takes suction from the normal ventilation exhaust duct of each of the three reactor zones and from the refueling zone that is independent of the normal ventilation system. Each filter train contains a moisture separator, a heater, a pre-filter, an upstream high efficiency particulate air (HEPA) filter, a charcoal filter, and a downstream HEPA filter. These three filter trains and blowers are arranged in parallel. The three blowers share a common discharge header that discharges to the plant stack 600 feet in elevation. The filter trains and blowers are located in the SGT building. The SGT system is normally in standby operation and will start automatically, when required.

The SGT system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the SGT system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- maintains negative pressure in the secondary containment on the primary containment system group six isolation signal
- filters airborne particulates and gases including those from the HPCI and CAD systems prior to discharge to the off-gas system
- maintains negative pressure in secondary containment on primary containment system signal due to radiation monitoring system refueling zone high radiation signal
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.2, the applicant identified the following SGT system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fittings, flexible connectors, piping, tubing, and valves.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and LRA Appendix F and UFSAR Sections 5.3.3, 7.12.5, and F.7.18 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.2.2, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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 responses.

In RAI 2.3.2.2-1, the staff requested the applicant to clarify whether all the system's components such as, but not limited to, fan housings, filter housing, damper housing, valve bodies, screens for intake and exhaust structures, and all other applicable components of the system, including duct sealants, wall sealants, pressure boundary sealants are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated November 3, 2004, and supplemented by a letter dated December 3, 2004, the applicant stated that all applicable system components consisting of fan housings, filter housing, damper housing, valve bodies including duct sealants, wall sealants, and pressure boundary sealants are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1) for the SGT system. The applicant also stated that structural sealants, such as those required to maintain the secondary containment at a negative pressure with respect to the adjacent areas, are contained in LRA Section 3.5.2.1.2 and Table 3.5.2.2 as component types "Compression Joints and Seals" and "Caulking and Sealants," and that the SGT system does not contain air intake/exhaust structures with screens (SGT system exhausts to the reinforced concrete chimney (plant stack) as addressed in LRA Section 2.4.6.1).

In LRA Section 2.3.5, "Notes Associated with the Section 2.3 Tables," "Component Types" are revised to reflect these components and, therefore, are part of LRA Table 2.3.2.2, "Standby Gas Treatment System" and LRA Table 3.2.2.2, "Standby Gas Treatment System-Summary of Aging Management Evaluation."

Based on its review, the staff found the applicant's response to RAI 2.3.2.2-1 acceptable. The applicant clarified that all applicable system components consisting of fan housings, filter housing, damper housing, valve bodies, and all other applicable components of the system, including duct sealants, wall sealants, and pressure boundary sealants are within the scope of license renewal, and subject to an AMR for the SGT system and are already included in “Component Types” in LRA Tables 2.3.2.2 and 3.2.2.2. Therefore, the staff’s concern described in RAI 2.3.2.2-1 is resolved.

2.3.2.2.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the SGT system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the SGT system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 High Pressure Coolant Injection System

2.3.2.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.3, the applicant described the HPCI system. The HPCI system, in conjunction with the other ECCSs, limits the peak fuel clad temperature, over the complete spectrum of possible break sizes in the RCPB, during design-basis accidents. The HPCI system also provides adequate core cooling for small breaks and depressurizes the reactor coolant systems to allow low-pressure coolant injection and core spray flow. In addition, the HPCI system provides reactor vessel make-up, pressure control, and decay heat removal during regulated events.

Each unit has an individual HPCI system and no components are shared; however, each unit’s HPCI pump may take suction from any unit’s condensate storage tank. The HPCI system consists of a single steam turbine-driven pump. The steam supply for the turbine comes from the MS system and exhausts to the suppression pool. The pump takes suction from the condensate storage tank, or the suppression pool, and discharges into the reactor vessel, through the feedwater (FW) system. A full-flow test line to the condensate storage tank is provided. During normal operation, the HPCI system is in standby. The HPCI system automatically starts if there is high pressure in the drywell or a low-water level in the reactor vessel.

The HPCI system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the HPCI system could prevent the satisfactory accomplishment of an SR function. In addition, the HPCI system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides an RCPB during HPCI system standby and operation
- provides a primary containment boundary during HPCI system standby and operation

- limits the loss of coolant through the HPCI system steam supply line break (passive, flow restrictor built into the steam line)
- provides a secondary containment boundary
- establishes a main steam safety isolation valve (MSIV) leakage pathway to the condenser
- provides coolant to the reactor vessel until it can be manually run in the condensate storage tank to condensate storage tank recirculation mode for pressure relief and decay heat
- provides debris protection
- provides for flow distribution
- restricts flow
- provides for heat transfer
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.3, the applicant identified the following HPCI system component types that are within the scope of license renewal and subject to an AMR: bolting, condenser, expansion joint, fittings, RCPB fittings, flexible connectors, gland seal blower, heat exchangers, piping, RCPB piping, pumps, restricting orifice, RCPB restricting orifice, strainers, tanks, traps, tubing, turbines, valves, and RCPB valves.

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 and UFSAR Sections 5.2.3, 5.3, 6.3, 6.4.1, and 7.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.2.3.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the HPCI system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the HPCI system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Residual Heat Removal System

2.3.2.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.4, the applicant described the RHR system. Each unit has two RHR system loops and each loop has two RHR pumps and two RHR heat exchangers. The pump suction header and the heat exchanger discharge header of one loop in Unit 1 and one loop in Unit 2 can be cross-connected. A similar cross-connection is provided between Unit 2 and Unit 3.

The RHR system provides a number of functions that are manually initiated. The RHR system provides shutdown cooling during normal operations and regulated events. The RHR system, in conjunction with the other ECCSs, also provides core flooding to limit the peak fuel clad temperatures over the complete spectrum of possible break sizes in the RCPB during design-basis accidents.

Provisions are provided within the RHR system, for both makeup and reject, to maintain the suppression pool level within the required limits. Cross-connections with the fuel pool cooling system allow the RHR heat exchangers to supplement heat removal and provide a permanent source of makeup water for the spent fuel pool.

The RHR contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the RHR could prevent the satisfactory accomplishment of an SR function. In addition, the RHR performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides suppression pool water cooling to maintain the suppression pool water temperature below limits to assure that pump net positive suction head requirements are met and that complete condensation of blowdown steam from a design-basis LOCA can be expected
- provides spray to drywell and torus for containment cooling and lowering of containment pressure under post-accident conditions
- provides a secondary containment boundary and a pressure boundary interface with the condensate ring header
- provides RCPB
- provides RHR system piping flow path for transmission of condensate and demineralized water system water supply to HPCI system piping upstream of HPCI system pump
- provides RHR system piping flow path from the HPCI system pump minimum flow coolant to the main RHR system heat exchangers

- provides debris protection
- provides for flow distribution
- restricts flow
- provides for heat transfer
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.4, the applicant identified the following RHR system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, heat exchangers, piping, RCPB piping, pumps, restricting orifice, strainers, tubing, valves, and RCPB valves.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 and UFSAR Sections 3.3, 4.1, 4.8, 5.2.3, 5.3, 6.4.4, 7.3, 7.4, 7.18, 9.2, 10.5, 10.9, 10.10, 10.17, F7.9, F7.15, and F7.16 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.2.4.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RHR system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RHR system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.5 Core Spray System

2.3.2.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.5, the applicant described the CS system. The CS system, in conjunction with the other ECCSs, provides spray cooling to the reactor core to limit the peak fuel clad temperature over the complete spectrum of possible break sizes in the RCPB during design-basis accidents. Each individual unit contains a separate CS system with two independent loops. Each loop has two pumps that can pump water from the suppression pool directed into the reactor vessel to the spray headers located above the core and within the core shroud. Some CS system components are located within the reactor vessel; these components are evaluated in the reactor vessel internals section of this SER.

Full-flow pump test capability is provided by discharge line to the suppression pool. During normal operation, the CS system is in standby and can be started automatically, when required. Full-flow suction lines from the condensate storage tanks penetrate the secondary containment and provide a suction flow path for the RCIC and HPCI systems.

The CS system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the CS system could prevent the satisfactory accomplishment of an SR function. In addition, the CS system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- supplies cooling water to the reactor (automatic initiation)
- provides RCPB
- provides a primary containment boundary
- provides a secondary containment boundary and pressure boundary interface with the condensate system ring header
- provides debris protection
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.5, the applicant identified the following CS system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, piping, RCPB piping, pumps, restricting orifice, RCPB restricting orifice, strainers, tanks, tubing, valves, and RCPB valves.

2.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5 and the UFSAR Sections 4.4, 5.2, 5.3, 6.4.3, 7.3, 7.4, 7.8, 10.10, and 11.7 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in the 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.2.5, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.2.5-1, the staff stated that the low pressure coolant injection (LPCI) coupling was identified in the BWRVIP-06 report as an SR component. It appears, however, that the component was not identified in the LRA as requiring an AMR. Therefore, the staff requested the applicant to justify its exclusion from aging management and to submit an AMR for the subject component.

In its response, by letter dated November 3, 2004, the applicant stated that BFN does not contain a LPCI coupling; therefore this component was not identified in the LRA. Therefore, the staff's concern described in RAI 2.3.2.5-1 is resolved.

2.3.2.5.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the CS system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the CS system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.6 Containment Inerting System

2.3.2.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.6, the applicant described the containment inerting system. The containment inerting system provides the capability to measure oxygen and hydrogen concentrations in the primary containment following an accident. A separate oxygen and hydrogen monitoring system, with two sampling loops, is provided for each unit. The loops have pumps that pump the drywell or torus atmosphere past the hydrogen and oxygen sensors and back to the torus. In the event of an accident, the containment inerting system would be manually started.

The containment inerting system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the containment inerting system could prevent the satisfactory accomplishment of an SR function. In addition, the containment inerting system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- provides oxygen and hydrogen gas analyzers and indicators to monitor gas concentrations inside the primary containment in support of CAD system operation,
- provides a primary containment boundary
- provides a secondary containment boundary
- provides debris protection
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.6, the applicant identified the following containment inerting system component types that are within the scope of license renewal and subject to an AMR: bolting, flexible connectors, heat exchangers, fittings, piping, pumps, strainers, traps, tubing, and valves.

2.3.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.6, LRA Appendix F, and UFSAR Section 5.2.6 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.2.6, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by the letter dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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 response.

In RAI 2.3.2.6-1, the staff requested that the applicant clarify whether the system components such as piping, valves, and equipment between FCV-76-17 and PC-V67-14, including the downstream bypass line after BYV-76-542, and between CKV-76-653 and CKV-76-659 depicted on LRA drawings 47E860-1-LR for Units 1, 2, and 3, are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated November 3, 2004, the applicant stated that all applicable system components between primary containment isolation valve FCV-76-17 and secondary containment isolation valve PCV-76-14, and between primary containment isolation valve CKV-76-653 and secondary containment isolation valve CKV-76-659 are not within scope for 10 CFR 54.4(a)(1). They are not within scope for 10 CFR 54.4(a)(3) since they are not required for any of the regulated events. Also, since these components are not liquid filled, they do not meet the criteria of 10 CFR 54.4(a)(2).

Based on its review, the staff found the applicant's response to RAI 2.3.2.6-1 acceptable. The applicant clarified why the above system components are not within the scope of license renewal. The applicant identified those portions of the containment inerting system that meet the scoping requirements of 10 CFR 54.4 and included them within the scope of license renewal in LRA Section 2.3.2.6. The applicant also included containment inerting system components that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a) (1) in LRA Table 2.3.2.6, "Containment Inerting System," and in LRA Table 3.2.2.6, "Containment Inerting System-Summary of Aging Management Evaluation." Therefore, the staff's concern described in RAI 2.3.2.6-1 is resolved.

2.3.2.6.3 Conclusion

The staff reviewed the LRA, the accompany scoping boundary drawings, and the RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the containment inerting system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the containment inerting system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.7 Containment Atmosphere Dilution System

2.3.2.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.7, the applicant described the CAD system. The CAD system is shared between Units 1, 2, and 3. The system consists of two trains, each of which is capable of supplying nitrogen through separate piping systems, to the drywell and suppression chamber. The system is in standby during normal operation and is started manually when required.

The CAD system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the CAD system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides for dilution of the primary containment atmosphere with nitrogen after a LOCA to maintain hydrogen and oxygen gas concentrations below a level that could produce a combustible mixture (five percent oxygen by volume)
- provides a primary containment boundary

- provides a secondary containment boundary
- provides nitrogen as the actuating medium for the reactor building to torus vacuum breaker butterfly valves when control air is not available
- provides nitrogen makeup to the MSRVs
- provides for heat transfer
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.2.7, the applicant identified the following CAD system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, flex hose, heat exchangers, piping, tanks, tubing, and valves.

2.3.2.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.7, LRA Appendix F, and UFSAR Sections 5.2.3 and 5.2.6 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 CAD system that meet the scoping requirements of 10 CFR 54.4 and included them within the scope of license renewal in LRA Section 2.3.2.7. The applicant also included CAD system components that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) in LRA Table 2.3.2.7, “Containment Atmosphere Dilution System,” and in LRA Table 3.2.2.7, “Containment Atmosphere Dilution System-Summary of Aging Management Evaluation.” LRA Section F.2, “Containment Atmosphere Dilution System Modifications,” indicates that Unit 1 capability to supply pressurized nitrogen to operate the MSRVs when control air is not available will be identical to the capability of Units 2 and 3 and will result in the same AMPs for each unit. This item will be discussed in SER Section 2.6.1.2.

2.3.2.7.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the CAD system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the CAD system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In LRA Section 2.3.3, the applicant identified the systems and components of the auxiliary systems that are subject to an AMR for license renewal in the following sections of the LRA:

- 2.3.3.1 auxiliary boiler system
- 2.3.3.2 fuel oil system
- 2.3.3.3 residual heat removal service water system
- 2.3.3.4 raw cooling water system
- 2.3.3.5 raw service water system
- 2.3.3.6 high pressure fire protection system
- 2.3.3.7 potable water system
- 2.3.3.8 ventilation system
- 2.3.3.9 heating, ventilation, and air conditioning system
- 2.3.3.10 control air system
- 2.3.3.11 service air system
- 2.3.3.12 CO_2 system
- 2.3.3.13 station drainage system
- 2.3.3.14 sampling and water quality system
- 2.3.3.15 building heat system
- 2.3.3.16 raw water chemical treatment system
- 2.3.3.17 demineralizer backwash air system
- 2.3.3.18 standby liquid control system
- 2.3.3.19 off-gas system
- 2.3.3.20 emergency equipment cooling water system
- 2.3.3.21 RWCU system
- 2.3.3.22 reactor building closed cooling water system
- 2.3.3.23 reactor core isolation cooling system
- 2.3.3.24 auxiliary decay heat removal system
- 2.3.3.25 radioactive waste treatment system
- 2.3.3.26 fuel pool cooling and cleanup system
- 2.3.3.27 fuel handling and storage system
- 2.3.3.28 diesel generator system
- 2.3.3.29 control rod drive system
- 2.3.3.30 diesel generator starting air system
- 2.3.3.31 radiation monitoring system
- 2.3.3.32 neutron monitoring system
- 2.3.3.33 traversing in-core probe system
- 2.3.3.34 cranes system

The corresponding sub-sections of this SER (2.3.3.1 – 2.3.3.34) present the staff's review findings for each system of the auxiliary systems.

2.3.3.1 Auxiliary Boiler System

2.3.3.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.1, the applicant described the auxiliary boiler system. The auxiliary boiler system provides heating and miscellaneous steam services within the power house. This includes the ability to test the HPCI system and the RCIC system turbines while the reactor is shutdown. This system is a plant-shared system. The turbine building contains three oil-fired, auxiliary boilers.

The auxiliary boiler system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the auxiliary boiler system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- establishes an MSIV pathway to the condenser
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.1, the applicant identified the following auxiliary boiler system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, pipes, traps, tubing, and valves.

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 and UFSAR Sections 5.2, 5.3, and 10.20 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the auxiliary boiler system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside of the secondary containment required to maintain the structural integrity of the secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the letter the applicant stated that piping was added to scope. The component types do not differ from those listed in LRA Table 2.3.3.1; therefore, no changes to the auxiliary boiler system portion of the LRA are required.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.1.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the auxiliary boiler system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the auxiliary boiler system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Fuel Oil System

2.3.3.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.2, the applicant described the fuel oil system. The fuel oil system is a plant-shared system; two large storage tanks are provided for the entire plant. Pumps transfer fuel oil to the auxiliary boilers and storage tanks for the various diesel-driven engines. The standby alternating current (AC) power fuel oil system consists of three interconnected storage tanks for each of the system’s eight diesel generators (DGs). Transfer pumps are provided to transfer fuel from a 7-day storage tank to the associated DG day tank. These 7-day storage tanks can provide sufficient fuel for the operation of the DGs during seven continuous days, following a LOCA. The system is in standby during normal operation and starts automatically, when required, to supply fuel to any operating DG. The other plant DGs each have a single storage tank.

The fuel oil system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the fuel oil system could prevent the satisfactory accomplishment of an SR function. In addition, the fuel oil system performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides diesel fuel oil to the DG system
- maintains a 7-day (long term) supply of fuel oil in storage tanks to support the DG system
- provides debris protection
- restricts flow

- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.2, the applicant identified the following fuel oil system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, flex hose, piping, pumps, restricting orifice, stainers, tanks, tubing, and valves.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 and UFSAR Section 8.5.3.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.2, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.2-1. the staff identified that components in the DG low level radioactive waste (LLRW) fuel oil subsystem and the diesel-driven fire pump LLRW fuel oil subsystem had not been included in the LRA as being within the scope of license renewal and subject to an AMR. The UFSAR does not describe either of these two subsystems. The staff is unable to determine if these subsystems have intended functions that would satisfy any of the criteria in 10 CFR 54.4(a). Therefore, the staff requested that the applicant provide the design functions and associated licensing bases of these portions of the fuel oil system to determine if they can be excluded from the scope of license renewal.

In its response, by letter dated October 19, 2004, the applicant stated that the two LLRW fuel oil subsystems provide fuel oil to the diesels to drive pumps that supply backup water to the ancillary facilities fire protection system. The areas protected by the ancillary facilities fire protection system are outside the protected area of the plant and are not required for plant shutdown.

Based on its review, the staff found the applicant's response to RAI 2.3.3.2-1 acceptable. The intended functions of these subsystems as described in the applicant's response are outside the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). Therefore, the staff's concern described in RAI 2.3.3.2-1 is resolved.

In RAI 2.3.3.2-2, the staff identified that a drain valve and associated piping and fittings on the diesel fuel tank for the diesel-driven fire pump had not been included in the LRA as being within the scope of license renewal and subject to an AMR. Failure of this piping could affect the upstream valve and drain the storage tank. Therefore, the staff requested that the applicant justify the exclusion of the drain valve and associated piping and fittings from the scope of license renewal.

In its response, by letter dated October 19, 2004, the applicant stated that none of the piping shown on the license renewal drawing is SR or seismically qualified; the piping is within the scope of license renewal for fire protection. Failure of the short section of piping and fittings downstream of normally closed valve, 0-DRV-703, would not cause the storage tank to drain.

Based on its review, the staff found the applicant's response to RAI 2.3.3.2-2 acceptable. There is a normally closed valve within the scope of license renewal upstream of the drain valve in question; thus, failure of the short section of piping and fittings downstream of this valve would not affect the intended function of the storage tank. Therefore, the staff's concern described in RAI 2.3.3.2-2 is resolved.

2.3.3.2.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the fuel oil system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the fuel oil system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.3 Residual Heat Removal Service Water System

2.3.3.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.3, the applicant described the RHRSW system. The RHRSW system is a plant-shared system. The system pumps water directly from Wheeler Reservoir through the RHR heat exchangers and EECW system components and discharges the water back into the Wheeler Reservoir.

The RHRSW system contains SR components that are relied upon to remain functional during, and following DBEs. The failure of NSR SSCs in the RHRSW could prevent the satisfactory accomplishment of an SR function. In addition, the RHRSW performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides cooling water to the RHR system heat exchangers
- provides cooling water to the EECW system upon start of the RHRSW pumps, given EECW valve position interlock signals

- provides a secondary containment boundary
- provides sump pump capability for RHRSW pump compartments
- provides debris protection
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.3, the applicant identified the following RHRSW system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, pumps, restricting orifice, strainers, tubing, and valves.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and UFSAR Sections 4.8, 5.3, 7.12.4, 7.18, 10.9, 10.10, 11.6, F.7.7, F.7.15, and F.7.16 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.3, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.3-1, the staff stated that license renewal drawing 0-47E851-4-LR provides the drainage flow diagram (identified as system number 40 in the drawing title block). Most of the piping and valves for system 40 on the drawing are identified with UNIDs; however, the piping on this drawing is shown in red, but does not identify UNIDs for the piping or pumps. Therefore, the staff requested the applicant to identify which components on this drawing are part of the RHRSW system.

In its response, by letter dated October 19, 2004, the applicant stated that the piping and pumps shown in red on drawing 0-47E851-4-LR are associated with the pumping station and are part of the RHRSW system (system 23). The pumps are tagged as RHRSW system 23 components and there are no UNIDs assigned to pipe. These components are part of the RHRSW and are contained in LRA Table 2.3.3.3.

Based on its review, the staff found the applicant's response to RAI 2.3.3.3-1 acceptable. It confirms that the piping and pumps shown in red on the license renewal drawing are part of the residual heat removal service water system and that the components in question are appropriately included in LRA Table 2.3.3.3. Therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

2.3.3.3.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawing, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RHRSW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RHRSW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Raw Cooling Water System

2.3.3.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.4, the applicant described the raw cooling water (RCW) system. The RCW system cools plant components (including components in the reactor building) during normal operations. The Unit 1 and Unit 2 RCW systems share pump suction and discharge headers and seven RCW pumps. The separate, Unit 3 RCW system has five pumps that have a separate suction header, but share a common discharge header with Units 1 and 2. Three pumps per unit are normally required. The RCW system has interfaces with the EECW system, which is normally inservice. The RCW pumps are located in the turbine building and are supplied from the condenser circulating water system.

The RCW system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the RCW system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides pressure boundary integrity for the EECW system
- provides a flow path through control room chillers A and B for Units 1 and 2 only
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.4, the applicant identified the following RCW system component types that are within the scope of license renewal and subject to an AMR: bolting, expansion joint, fittings, flex hose, piping, pumps, strainers, tubing and valves.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Sections 5.3, 10.7, and F.6.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.4, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.4-1, the staff identified that water chillers 1A and 1B on license renewal drawing 1-47E844-2-LR are not subject to an AMR, and heat exchangers are not listed as a component type in LRA Table 2.3.3.4. The shell of the chillers serves as the pressure boundary and structural support for the attached raw cooling water piping which is subject to an AMR. Therefore, the staff requested that the applicant justify the exclusion of these chillers from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that the piping on the shell side of water chillers 1A and 1B had been removed to show these chillers abandoned in place on drawing 1-47E844-1-LR. Since the raw water piping has been removed, the chillers no longer perform a pressure boundary or structural support function. The applicant further stated that the drawing has been revised and will be sent to the staff as part of the annual update.

Based on its review, the staff found the applicant's response to RAI 2.3.3.4-1 acceptable. Water chillers 1A and 1B no longer perform an intended function in accordance with the requirements of 10 CFR 54.4(a) and are outside the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.4-1 is resolved.

In order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the raw cooling water system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside of the secondary containment required to maintain the structural integrity of the secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the letter the applicant stated that piping was added to scope. The component types do not differ from those listed in LRA Table 2.3.3.4; therefore, no changes to the raw cooling water system portion of the LRA are required.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.4.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RCW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Raw Service Water System

2.3.3.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.5, the applicant described the raw service water (RSW) system. The RSW system furnishes water for yard-watering and the cooling of miscellaneous plant equipment that requires only small quantities of cooling water. The system also functions as a ‘keep-fill’ system for the fire protection system. The RSW system is supplied from river water from the condenser circulating water inlet conduit, through a strainer, and to the main RCW pump suction header for each unit. Units 1 and 2 each have one RSW pump; Unit 3 has two RSW pumps. Therefore, four pumps supply the common plant system. Two 10,000-gallon storage tanks are located on top of the reactor building. These tanks pressurize the high pressure fire protection (HPFP) system header.

The RSW system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the RSW system performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides a keep-fill system for the fire protection system
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.5, the applicant identified the following RSW system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, tanks, tubing, and valves.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 and UFSAR Sections 5.3, 10.8, 10.10, and F.6.6 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.5, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI 2.3.3.5-1, the staff identified that the raw service water components upstream of valve 1-25-703 are not included in the LRA as being within the scope of license renewal and subject to an AMR. Similar arrangements exist for Units 2 and 3. This normally open, hand-operated valve is located at the interface between the discharge of RSW pump 1A and the fire service system. Therefore, the staff requested that the applicant provide the basis for using a normally open, hand-operated valve as a pressure boundary from the upstream RSW system piping and components. The staff also requested that the applicant justify the exclusion of these components from the scope of license renewal.

In its response, by letter dated October 19, 2004, the applicant stated that the fire protection capability to control and extinguish fires is not dependent on the operability of the raw service water pumps. Therefore, these pumps are not in scope, and any piping and valves associated with the RSW system are also not included within the scope of license renewal. Additionally, the applicant stated that valve 1-25-703 is the first isolation valve off the 12-inch fire protection headers tie-in to the RSW pumps, and is within the scope of license renewal as it provides an isolable point between the RSW and fire protection systems.

Based on its review, the staff found the applicant's response to RAI 2.3.3.5-1 acceptable. The RSW pumps and associated components do not perform an intended function in accordance with the requirements of 10 CFR 54.4(a), and are, therefore, outside the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.5-1 is resolved.

2.3.3.5.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RSW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RSW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 High Pressure Fire Protection System

2.3.3.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.6, the applicant described the HPFP system. The HPFP system supplies water for fixed water spray, pre-action sprinkler, and aqueous foam systems for selected equipment and areas in the control building, reactor buildings, turbine building, intake pumping station, hydrogen trailer port, transformer yard, DG buildings, and service buildings.

The HPFP system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the HPFP system could prevent the satisfactory accomplishment of an SR function. In addition, the HPFP system performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- supports a secondary containment function
- provides automatic fire protection for known hazardous areas where it is practical
- provides adequate warning of a fire in hazardous areas where automatic protection is not feasible to provide adequate manually-actuated fire protection systems for the entire plant and yard areas (i.e., hose stations, hydrants, etc.)
- ensures the maintenance of divisional integrity of SR systems to the extent that the capability for safe shutdown of the reactors is assured during and after a fire
- provides debris protection
- provides mechanical closure
- provides pressure boundary
- provides spray pattern
- provides structural support

In LRA Table 2.3.3.6, the applicant identified the following HPFP system component types that are within the scope of license renewal and subject to an AMR: bolting, fan housing, fire hydrants, fire hose stations, fittings, flexible connectors, heaters, heat exchangers, piping, pumps, restricting orifice, silencer, sprinkler heads, strainers, tanks, tubing, and valves.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6 and UFSAR Sections 10.11 and F.6.9 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). In addition, the staff also reviewed the BFN Fire Protection Report (FPR) (Volumes 1 and 2). This report is referenced directly in the BFN fire protection CLB and summarizes the fire protection program and commitments to 10 CFR 50.48 using the guidance of Appendix A to Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.6, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 23, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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 and staff evaluation.

In RAI 2.3.3.6-1, the staff stated that the system description of the HPFP system in LRA Section 2.3.3.6 includes fixed water spray systems. Such systems typically utilize water spray nozzles. The staff identified that LRA Table 2.3.3.6 does not include water spray nozzles as a component subject to an AMR. Therefore, the staff requested that the applicant indicate whether the fixed water spray systems use spray nozzles other than the sprinkler heads. If so, staff stated that the nozzles, which are intended to support the system function, are passive and long-lived and should be subject to an AMR.

In its response, by letter dated September 30, 2004, the applicant stated that fire protection spray nozzles (including spray nozzles attached to fire hoses) had been included in component type "sprinkler heads" in LRA Table 2.3.3.6.

Based on its review, the staff found the applicant's response to RAI 2.3.3.6-1 acceptable. The components in question are included in scope and are subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.6-1 is resolved.

In RAI 2.3.3.6-2, the staff stated that the system description of the HPFP system in LRA Section 2.3.3.6 describes detection and alarm devices that automatically initiate the system or prompt manual fire fighting. The staff stated that these devices are not identified on the license renewal drawings, nor are they discussed in the fire protection program. Therefore, the staff requested that the applicant explain what these devices are and whether they are subject to an AMR.

In its response, by letter dated September 30, 2004, the applicant stated that the alarm and detection devices do not perform a pressure boundary function, are active components, and are evaluated as electrical commodities.

Based on its review, the staff found the applicant's response to RAI 2.3.3.6-2 acceptable. The components in question are electrical, not mechanical, and are active, and therefore are not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.6-2 is resolved.

In RAI 2.3.3.6-3, the staff stated that the LRA shows that the boundary of the HPFP system is the service building wall. The staff stated that the boundary shown is not at an isolated pressure boundary (e.g., a valve or blank flange). Therefore, the staff requested that the applicant justify the exclusion of the service building portions of the system from the scope of license renewal.

In its response, by letter dated September 30, 2004, the applicant stated that the boundary does not end at the service building wall but continues on license renewal drawing 1-47E850-2-LR. BFN drawings depict continuation to other drawings with drawing coordinate flags. For clarification, the reference to drawing coordinate flag 1-47E850-2 G6 should have been colored red on license renewal drawing 1-47E850-1-LR. The boundary should end at the isolation valve 0-26-907 on drawing 1-47E850-2-LR. The boundary extends to an appropriate isolation valve.

Based on its review, the staff found the applicant's response to RAI 2.3.3.6-3 acceptable. The boundary extends to an appropriate isolation valve. Therefore, the staff's concern described in RAI 2.3.3.6-3 is resolved.

In RAI 2.3.3.6-4, the staff stated that the LRA identifies a water curtain around the equipment hatch at elevation 565 feet. Table 9.3.11.B in Volume 1 of the FPR lists water curtains for the RHR pump room equipment hatches at elevation 541 feet. The staff identified that the license renewal drawings do not show anything on elevation 541 feet. Therefore, the staff requested that the applicant clarify that the water curtain protection for the RHR pump room equipment hatches are within the scope of license renewal, and identify where they are located on the license renewal drawings.

In its response, by letter, dated September 30, 2004, the applicant stated that the water curtains at BFN are typically provided to protect floor openings and include closely spaced sprinklers and draft stops located around the opening underneath the floor slab. In Unit 3 reactor building elevation 565 feet, as shown on license renewal drawing 3-47E850-5, water curtains are provided at the following six different locations:

(1) equipment hatch in floor opening above (between floor elevation 565 feet and 593 feet)

(2) stair #22 floor opening above (between floor elevation 565 feet and 593 feet)

(3) east RHRSW heat exchanger (HX) room portal (door opening)

(4) west RHRSW HX room portal (door opening)

(5) east RHRSW HX room floor opening below (between elevation 541 feet and 565 feet)

(6) west RHRSW HX room floor opening below (between elevation 541 feet and 565 feet)

The water curtains (5 and 6) in the RHRSW HX room floor opening are located below elevation 565 feet floor slab to protect the opening from the fire effects of elevation 541 feet. These two water curtains are the ones described in Table 9.3.11.B, Volume 1 of the FPR as the water curtains for the RHR pump room equipment hatches at elevation 541 feet. These water curtains are within the scope of license renewal.

Based on its review, the staff found the applicant's response to RAI 2.3.3.6-4 acceptable. The water curtains in question were verified by the applicant to be within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.6-4 is resolved.

In reviewing the FPR, the staff identified the need for additional information related to the fire water supply systems and fire protection coating. In a letter dated August 23, 2004, the staff asked the applicant to clarify information contained in the FPR Volume 1, Sections 4.4.1.A and 4.4.5. The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 4.4.1-1, the staff stated that FPR Section 4.4.1.A addresses a separate water supply system, including tank and pumps, which does not appear in the LRA or boundary drawings. In RAI 4.4.1-1, the staff requested the applicant to verify whether these system components are within the scope of license renewal and provide the justification if they are not.

In its response, by letter dated September 30, 2004, the applicant stated that the separate water supply ID referring to the outside loop is not within the scope of license renewal, since it is servicing NSR areas of the plant that provide equipment/property protection and meet the Nuclear Electric Insurance Limited (NEIL) requirements. Therefore, they do not meet any criteria of 10 CFR 54.4.

Based on it review, the staff found the applicant's response to RAI 4.4.1-1 acceptable. Even though the separate water supply can be connected to the HPFP system as a backup identified in plant procedures, it is not connected by fixed piping and valves. Therefore, the staff concurred that the separate water supply is not within the scope of license renewal, and the staff concern described in RAI 4.4.1-1 is resolved.

In RAI 4.4.5-1, the staff stated that FPR Section 4.4.5 states that "Flamemastic" was applied to cables that did not meet Institute of Electrical and Electronics Engineers (IEEE)-383 flame test requirements. Inspection Testing and Maintenance of this is not referenced in the FPR. No reference is made to it in the LRA, either under the Fire Protection Program, LRA Section B.2.1.23, or in the electrical or structural programs. Therefore, the staff requested that the applicant supply the AMR and AMP that are applicable to the Flamemastic coating. The staff also asked the applicant to include program documents and procedures credited for managing the loss of material for Flamemastic coating.

In its response, by letter dated September 30, 2004, the applicant stated that Flamemastic is primarily used as a flame retardant on non-IEEE-383 qualified cables. This commitment originated as part of the post-Fire Recovery Plan. As stated in the FPR, current practice is to use cables that meet the IEEE-383 requirements for flame retardant and, therefore, Flamemastic is not applied to these cables. Since Flamemastic is not considered a fire stop or a fire-resistive barrier, the 10 CFR Part 50, Appendix R, safe-shutdown analysis does not take credit for it. Some cable tray penetration seal assemblies, however, use a coating of Flamemastic on the fiber board and cables around the opening to meet the fire barrier function.

Materials listed in LRA Sections 3.5.2.1.2 and 3.5.2.1.5 should include Flamemastic coatings, when used in a qualified fire barrier configuration, to include both sides of the reactor building/turbine building wall cable tray penetrations.

By letter dated January 25, 2005, applicant stated that the aging effects requiring management were incorrectly assigned to Flamemastic when used in the qualified fire barrier configuration. At BFN, fire barrier penetration seal materials and Flamemastic coatings on exposed cables in open trays are exposed to an inside air environment and, therefore, have no aging effects and require no AMP.

The applicant further stated that, based on the above discussion, aging effects were also incorrectly assigned to fire barrier materials Thermolag, Elastomers, and Gypsum. LRA Section 3.5 will be revised to update the aging effects requiring management for these fire barrier materials.

Based on review of the applicant's response, as supplemented by letter dated January 25, 2005, the staff concurred that the proposed modifications to the LRA are appropriate, because Flamemastic coating on exposed cable trays are exposed to an inside air environment and require no AMR and AMP but are included within the scope of license renewal. Therefore, the staff's concern described in RAI 4.4.5-1 is resolved.

In addition, the staff, during its audit review held during the week of July 21 - 25, 2004, discussed the following issue for the Fire Protection Program.

In its letter, dated October 28, 2004, the applicant stated that Procedure FP-0-041-INS008, Process Computer Room Halon 1301 System Functional Test, identifies a Halon 1301 total flooding system on elevation 539 feet of the Control Bay (room 594.0-C1). No reference to Halon systems appears in the LRA (scoping, screening, AMR or AMP.) The applicant was requested to justify the exclusion of this system from license renewal.

The applicant also stated in its response that the Halon system does not provide fire protection for any equipment for plant shutdown but is installed to provide equipment/property protection and meet NEIL requirements. Therefore, this system does not meet any of the criteria of 10 CFR 54.4. Based upon its review, the staff agreed that the Halon 1301 systems identified in FP-0-041-INS008 are not part of the plant licensing basis and, therefore, are not within the scope of license renewal. The staff concern described above is resolved.

2.3.3.6.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the HPFP system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the HPFP system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Potable Water System

2.3.3.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.7, the applicant described the potable water system. The potable water system supplies potable water for use in the plumbing systems and is supplied by the city of Athens, AL. Potable water is supplied to various areas in the plant. Backflow preventers are installed at each interface between the potable water system and the separate connecting systems, in order to protect the potable water supply from possible contamination due to backflow. The potable water system is a plant-shared system.

The potable water system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the potable water system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.7, the applicant identified the following potable water system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, tubing, and valves.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 and UFSAR Sections 5.3, 10.15, and F.6.11 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the potable water system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside of the secondary containment required to maintain the structural integrity of the secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the letter the applicant stated that new component types, valves and tanks, were added to the scope as referenced in new LRA Tables 2.3.3.7 and 3.3.2.7.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.7.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the potable water system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the potable water system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Ventilation System

2.3.3.8.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.8, the applicant described the ventilation system. The ventilation system contains subsystems that provide ventilation and heating for various plant buildings, including the radioactive waste building and the DG buildings. The ventilation system does not include the HVAC systems or the reactor building ventilation systems. These systems are discussed in SER Section 2.3.3.9. The ventilation system is a plant-shared system.

The radioactive waste building ventilation system consists of two 50-percent capacity supply fans that filter air to central areas on the various plant floor levels. The ventilation systems for the DG buildings are designed to maintain the required environmental conditions for SR equipment located in the Unit 1, 2, and 3 DG buildings.

The ventilation system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the ventilation system performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides ventilation to the Unit 1, 2, and 3 DG buildings
- provides ventilation to the 250 volt (V) Battery Room 3EB in the Unit 3 DG building to prevent the buildup of hydrogen gas during battery charging
- provides for secondary containment integrity (passive)
- provides debris protection
- provides fire barrier

- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.8, the applicant identified the following ventilation system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fire dampers, and fittings.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Sections 2.3.3.8 and BFN Units 1, 2, and 3 UFSAR Sections 5.3 and 10.12, and F.7.11 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.8, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by the letter dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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 responses.

In RAI 2.3.3.8-1, the staff requested that the applicant clarify whether all the system components such as, but not limited to, damper housings including fire damper housings, fan housings, air intake and exhaust structures including screens, supply and exhaust grills, etc., are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated November 3, 2004, and supplemented by a letter dated December 3, 2004, the applicant stated that (1) the damper housings and fan housings are included in component type "ductwork" in LRA Table 2.3.3.8, (2) fire damper housings are included in component type "fire dampers" in LRA Table 2.3.3.8, (3) screens associated with the exhaust plenum in the Units 1 & 2 DG building and the Unit 3 DG building are included in component type "ductwork" in LRA Table 2.3.3.8, and (4) intake/exhaust plenums associated with the DG buildings are considered part of the structure and are contained in LRA Table 2.4.3.1 and LRA Table 3.5.2.5. LRA Section 2.3.5, "Notes Associated with the Section 2.3 Tables," "Component Types" are revised to reflect these components and, therefore, are part of LRA Table 2.3.3.8, "ventilation system" and LRA Table 3.3.2.8, "Ventilation System-Summary of Aging Management Evaluation."

Based on its review, the staff found the applicant's response to RAI 2.3.3.8-1 acceptable. The applicant clarified that all applicable system components consisting of damper housings including fire damper housings, fan housings, air intake and exhaust structures including screens and all other applicable components of the system are within the scope of license renewal, and subject to an AMR for the ventilation system. Supply and exhaust grills do not perform any SR function, therefore, are excluded from the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.8-1 for those "Component Types" in LRA Tables 2.3.3.8 and 3.3.2.8 is resolved.

2.3.3.8.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the ventilation system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the ventilation system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Heating, Ventilation, and Air Conditioning System

2.3.3.9.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.9, the applicant described the HVAC system. The HVAC subsystems provide air-conditioned ventilation for various plant areas. The various HVAC subsystems provide environmental control, ventilation, and cooling. Ventilation and cooling is provided so that the temperatures of the control bay and shutdown electrical board rooms (including those in the Unit 3 DG building) are maintained within acceptable limits for the operation of instruments and other equipment during accidents and events. Ventilation is also provided to the battery room to prevent the buildup of explosive gases. In addition, the HVAC subsystems provide for the cooling of various electrical equipment rooms (e.g., computer and communications rooms) so that their temperatures are maintained within acceptable limits for the operation of instruments and other equipment.

The HVAC system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the HVAC system could prevent the satisfactory accomplishment of an SR function. In addition, the HVAC system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- isolates supply ducts and supplies pressurized filtered outdoor air to main control room on primary containment isolation system group six signal or radiation monitoring system initiation signal
- provides ventilation to cable spreading rooms and control bay mechanical equipment rooms

- recirculates cool air to the reactor building board rooms
- provides ventilation and air conditioning to the board rooms of the Unit 3 DG buildings and ventilation to the battery rooms
- provides recirculation air conditioning to control rooms and auxiliary instrument rooms
- provides manual lineup of HVAC equipment with total loss of control air
- provides a secondary containment boundary
- provides debris protection
- provides fire barrier
- provides for heat transfer
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.9, the applicant identified the following HVAC system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fire dampers, fittings, flexible connectors, heat exchangers, heaters, piping, pumps, refrigerant compressor, strainers, tanks, tubing, and valves.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 and UFSAR Sections 10.12 and F.7.11 using the evaluation methodology described in SER Section 2.3. 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 in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.9, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by the letter dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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 responses.

In RAI 2.3.3.9-1, the staff requested that the applicant clarify whether all the system components such as, but not limited to, fan housings, filter housings, cooling coil housings, damper housings including fire damper housings, metal lath screens, valve bodies, supply and return grills, and all other applicable components of the system, including duct sealants, wall sealants, pressure boundary sealants, screens for intake and exhaust structures, etc., are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated November 3, 2004, and supplemented by a letter dated December 3, 2004, the applicant stated the following:

- Fan housings, filter housings, cooling coil housings, and damper housings are included in component type “ductwork” in LRA Table 2.3.3.9.
- Metal lath screens shown on drawings 0-47E865-8-LR and 3-47E865-8-LR are included in component type “ductwork” in LRA Table 2.3.3.8.
- Screens and plenums will be included in the component type “ductwork.”
- LRA Table 3.3.2.9 will be revised to include “outside air (external)” for “ductwork.” A new row will be added for stainless steel “bolting” category with an outside air environment.
- Valve bodies are included in component type “valves” in LRA Table 2.3.3.9.
- Structural sealants such as those required to maintain the control room envelope or secondary containment are contained in Section 3.5.2.1.2 and in component type “compression joints and seals” and in component type “caulking and sealants” in LRA Table 3.5.2.2,
- Pressure boundary sealants associated with ductwork for HVAC system are included in component type “ductwork” in LRA Tables 2.3.3.9 and 3.3.2.9, and screens and plenums are included in the component type “ductwork.”

The supply and return grilles have no 10 CFR 54.4(a)1, 10 CFR 54.4(a)2, or 10 CFR 54.4(a)3 functions for license renewal and are not included in the LRA Tables. LRA Section 2.3.5, “Notes Associated with the LRA Section 2.3 tables,” “Component Types” is revised to reflect these components and, therefore, is part of LRA Table 2.3.3.9, “Heating, Ventilation, and Air Conditioning System,” and LRA Table 3.3.2.9, “Heating, Ventilation, and Air Conditioning System-Summary of Aging Management Evaluation.”

Based on its review, the staff found the applicant’s response to RAI 2.3.3.9-1 acceptable. The applicant clarified that all applicable system components consisting of fan housings, filter housings, cooling coil housings, damper housings, metal lath screens, screens and plenums, valve bodies, structural sealants to maintain the control room envelope including compression joints and seals, and pressure boundary sealants associated with ductwork are within the scope of license renewal, and subject to an AMR for the HVACS and are already included in “Component Types” in LRA Tables 2.3.3.9 and 3.3.2.9. Therefore, the staff’s concern described in RAI 2.3.3.9-1 is resolved.

2.3.3.9.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the HVAC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the HVAC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Control Air System

2.3.3.10.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.10, the applicant described the control air system. The control air system provides motive power for numerous plant components during normal operations and post-accident motive power to the torus vacuum breaker valves. The system also provides post-accident motive power to the MS isolation valves and the main steam safety relief valves (MSRVs) for reactor vessel overpressure relief protection and reactor vessel depressurization, including the ECCS automatic depressurization function.

The control air system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the control air system could prevent the satisfactory accomplishment of an SR function. In addition, the control air system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- performs isolation action(s) upon receiving primary containment system (64D) group six isolation signals
- provides compressed air to the MS system atmospheric dilution system (ADS) safety relief valves
- provides compressed air for closure of the MSIVs
- provide primary containment boundary
- provides compressed air to equipment access air lock seals to provide a secondary containment boundary
- provides and supports the secondary containment boundary
- provides for flow path integrity for supply of CAD nitrogen to the torus vacuum breaker valves
- provides a flow path for the CAD system to provide nitrogen to MSRVs
- provides for flow distribution
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.10, the applicant identified the following control air system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, flexible connectors, heat exchangers, piping, restricting orifice, tanks, tubing, and valves.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 and UFSAR Sections 5.2.3, 5.3, 10.14, and F.6.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.3.10.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the control air system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the control air system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Service Air System

2.3.3.11.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.11, the applicant described the service air system. The service air system is a plant-shared system and consists of two air compressors that are located in the turbine building. The system’s primary function is to provide pressurized air to hose connections throughout the plant yard and to miscellaneous equipment in the standby liquid control (SLC) system, Amertap condenser tube cleaning system (a subsystem of the condenser circulating water system), condensate demineralizer air surge system, and the radwaste system.

The service air system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.11, the applicant identified the following service air system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, and valves.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 and UFSAR Sections 5.2.3, 5.3, 10.14, and F.6.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the service air system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside of the secondary containment required to maintain the structural integrity of the secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the letter the applicant stated that piping, fittings, and valves were added to scope. The component types do not differ from those listed in LRA Table 2.3.3.11; therefore, no changes to the service air system portion of the LRA are required.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.11.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the service air system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the service air system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 CO_2 System

2.3.3.12.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.12, the applicant described the CO_2 system. The CO_2 system is a fire suppression system for the DG buildings, turbine building, and control bay spaces that contain electrical, lubricating oil, or fuel oil components. Units 1 and 2 share a system that includes a 17-ton storage tank. Unit 3 has a separate system with a 6-ton tank. The system is in standby during normal operation and initiates automatically, as required. When initiated, ventilation systems that could reduce the effectiveness of the CO_2 discharge are isolated. Detection and alarm devices that automatically initiate the system, or would prompt manual fire firefighting activities, are also included in the CO_2 system. The CO_2 system performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides CO_2 fire protection for oil and electrical hazards affecting the minimum safe shutdown system (SSDS) components required to achieve safe shutdown capability
- provides fire barrier
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.12, the applicant identified the following CO_2 system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fire dampers, fittings, piping, rupture disk, tanks, tubing, and valves.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 and UFSAR Sections 10.11 and F.6.9 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). In addition, the staff also reviewed BFN FPR volumes 1 and 2. This report is referenced directly in the fire protection CLB and summarizes the Fire Protection Program and commitments to 10 CFR 50.48 using the guidance of Appendix A to BTP APCSB 9.5-1. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.12, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results.

Therefore, by letter to the applicant dated August 23, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.12-1, the staff stated that the CO_2 system addressed in LRA Section 2.3.3.12 typically requires discharge nozzles to achieve the proper flow rate. The staff identified that the system description and LRA Table 2.3.3.12 do not include any reference to discharge nozzles. Therefore, the staff requested the applicant to indicate whether this system includes discharge nozzles. If so, the staff stated that the nozzles, which perform an intended function for flow control, are passive and long lived and should be subject to an AMR.

In its response, by letter dated September 30, 2004, the applicant stated that the discharge nozzles were included within component type "fittings" in Table 2.3.3.12 with an intended function of pressure boundary and subject to an AMR.

Based on the response, the staff concurred that the nozzles are within the scope of license renewal and subject to an AMR, but disagreed that the intended function is pressure boundary. The nozzles contain open orifices and serve a flow control function rather than a pressure boundary. The staff reviewed plant procedures 0-SI-4.11.D.1.b, 1/2-SI-4.11.D.1.b, and 3-SI-4.11.D.1.b for CO_2 system functional testing and found the nozzles are adequately addressed in the fire protection AMP. Therefore, the staff concern described in RAI 2.3.3.12-1 is resolved.

In RAI 2.3.3.12-2, the staff stated that the system description of the CO_2 system in LRA Section 2.3.3.12 addresses detection and alarm devices that automatically initiate the system or prompt manual fire fighting. The staff stated that these devices are not identified on the license renewal drawings, nor are they discussed in the Fire Protection Program. Therefore, the staff requested that the applicant explain what these devices are and whether they are subject to an AMR.

In its response, by letter dated September 30, 2004, the applicant stated that the CO_2 system fire protection detection and alarm devices do not form a pressure boundary and are active components and evaluated as electrical commodities.

Based on its review, the staff found the applicant's response to RAI 2.3.3.12-2 acceptable. The components in question are electrical, not mechanical, and are therefore active and not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.12-2 is resolved.

2.3.3.12.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the CO_2 system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the CO_2 system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.13 Station Drainage System

2.3.3.13.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.13, the applicant described the station drainage system. The station drainage system is a plant-shared system that collects, processes, stores, and disposes of non-radioactive liquid waste. Portions of the piping within the system penetrate the secondary containment.

The station drainage system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the station drainage system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.13, the applicant identified the following station drainage system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, and valves.

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13 and UFSAR Sections 5.3 and 10.16 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.13, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI 2.3.3.13-1, the staff identified a 3-inch roof drain (at roof elevation 667 feet on license renewal drawing 0-47E851-1-LR,) that is not within the scope of license renewal and subject to an AMR. This drain provides a pressure boundary function between the standby gas treatment system and the off-gas system; thus it should be within the scope of license renewal. The staff noted that a 4-inch roof drain on the same drawing is shown as being subject to an AMR. Therefore, the staff requested that the applicant justify the exclusion of the 3-inch roof drain from the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that the 3-inch roof drain should have been colored in red on drawing 0-47E851-1-LR, since it is within the scope of license renewal as part of the component type “fittings” in LRA Table 2.3.3.13 and subject to an AMR. The applicant further stated that drawing 0-47E851-1-LR has been revised to show the 3-inch roof drain highlighted in red and will be resent as part of the annual update.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.13-1 acceptable. It concurs that the 3-inch roof drain should be within the scope of license renewal and the drain included in LRA Table 2.3.3.13 as a component type subject to an AMR. Therefore, the staff’s concern described in RAI 2.3.3.13-1 is resolved.

In order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the station drainage system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside of the secondary containment required to maintain the structural integrity of the secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the letter the applicant stated that piping, fittings, and check valves were added to scope. The component types do not differ from those listed in LRA Table 2.3.3.13; therefore, no changes to the station drainage system portion of the LRA are required.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.13.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawing, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the station drainage system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the station drainage system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Sampling and Water Quality System

2.3.3.14.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.14, the applicant described the sampling and water quality system. The sampling and water quality system provides the capability to obtain representative samples for testing. The data are used to evaluate the performance of the plant, equipment, and systems during normal plant operations. Using a post-accident sample subsystem, representative samples of reactor coolant, torus liquid, drywell atmosphere, torus atmosphere, and secondary containment atmosphere can be obtained after a LOCA to guide post-LOCA actions regarding Units 2 and 3. Portions of the system are credited in analyses for MSIV alternate leakage treatment.

The sampling and water quality system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the sampling and water quality system could prevent the satisfactory accomplishment of an SR function. In addition, the sampling and water quality system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides primary and secondary containment boundaries
- maintains residual heat removal service water system pressure boundary integrity
- provides a pressure boundary of the sampling and water quality system components connected to the control air system that must maintain a pressure boundary in order to supply the CAD and MSRVs
- establishes MSIV leakage pathway to the condenser
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.14, the applicant identified the following sampling and water quality system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, flexible connectors, heat exchangers, piping, RCPB piping, pumps, strainers, tanks, tubing, valves, and RCPB valves.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14 and UFSAR Sections 5.2.3, 5.3, 10.17, and 10.21 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.14, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI F 2.3.3.14-1, the staff stated that LRA Section 2.3.3.14 states that one of the intended functions of the sampling and water quality system is to establish an MSIV leakage pathway to the condenser. The Unit 2 sampling lines from the main steam system are identified as being within the scope of license renewal and subject to an AMR; however, similar piping and components for Unit 1 are not identified as being within the scope of license renewal. Based on the information in the LRA, the staff could not determine why this portion of the Unit 1 sampling and water quality system is not within the scope of license renewal and subject to an AMR. Therefore, the staff requested that the applicant explain why this portion of the piping is not within the scope of license renewal and subject to an AMR.

In its response, by letter dated October 25, 2004, the applicant stated that license renewal drawings depict components subject to an AMR based on the unit's CLB. As documented in LRA Section F.1, the Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing main steam piping and the main condenser, because this modification currently is not physically implemented for Unit 1 to match Units 2 and 3 in their configuration.

The LRA was structured to reflect CLB and configuration of all three units. Therefore, scoping and screening was done based on the CLB and configuration of all three units. The differences between the units that are relevant to the application and will be resolved prior to Unit 1 restart are listed in LRA Appendix F. This issue will be discussed in SER Section 2.6.1.1.

In addition, by letter dated January 31, 2005, the applicant provided additional supplementary information, stating that as each activity identified in LRA Appendix F is completed, the corresponding bold-bordered text in the LRA will apply to Unit 1. The applicant stated in its response that the only change to the application will be to remove the bolded border. No changes are required for scoping and screening, AMR, or TLAAs; however, in some cases, boundary drawings would change to reflect the bolded bordered text. The applicant committed to perform a secondary application review for the staff during the annual update after the modification is implemented in the plant. This will assure that the design changes to implement this modification do not modify or change the basis of how these components were initially scoped and screened.

Based on its review, the staff found the applicant's response to RAI F 2.3.3.14-1 acceptable. The Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing the main steam piping and main condenser; therefore, this portion of piping is not subject to an AMR. Upon completion of the modification discussed in LRA Appendix F and the January 31, 2005 letter, the CLB for Unit 1 will be the same as that for Units 2 and 3. The review of LRA Appendix F regarding Unit 1 restart will be addressed in SER Section 2.6.1.1. Therefore, the staff's concern described in RAI F 2.3.3.14-1 is resolved.

In order to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1, the applicant expanded the system boundaries for the sampling and water quality system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the result of its review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the 10 CFR 54.4(a)(2) cases where NSR piping or components are directly connected to SR piping or components. In February 28, 2005, letter, Enclosure 2, "Mechanical Systems," the applicant stated that additional components, grab sample boxes, had been added to scope that are credited as anchorage in the seismic analysis. As a result, the component type panel was added to LRA Table 2.3.3.14.

The staff reviewed the identify support/equivalent anchors and the seismic Class II piping segments up to the first anchor point of the seismic Class I piping boundaries provided in the Enclosure 2 of the letter, dated February 28, 2005. The staff found the expanded scope of components to be acceptable because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.14.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the sampling and water quality system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the sampling and water quality system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Building Heat System

2.3.3.15.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.15, the applicant described the building heat system. The building heat system is a plant-shared system that maintains the required temperatures for equipment protection and personnel comfort during the winter months. As required, the system uses forced, hot water to maintain a minimum temperature of 55 °F in various plant buildings, including the reactor building. Hot water required for the system is heated by the auxiliary boiler system and preheats the building intake air.

The building heat system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.15, the applicant identified the following building heat system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, heaters, piping, pumps, and valves.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 and UFSAR Sections 5.3.3.6 and 10.12.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.15, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI 2.3.3.15-1, the staff stated that LRA Section 2.3.3.15 states that the intended function of the building heat system is to provide a secondary containment boundary. The staff identified that valves 1-1029, 1-1030, 2-1318, 2-1319, 3-1386, and 3-1387 are included in the scope of license renewal and subject to an AMR, but the connected piping on one side of these valves is not included within the scope of license renewal and not subject to an AMR. The staff could not determine if the piping on both sides of these open valves provides a secondary containment boundary. Therefore, the staff requested that the applicant provide a basis for these valves being the boundary of the piping and components that are not subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that valves 1-1029, 1-1030, 2-1318, 2-1319, 3-1386, and 3-1387 were included in the scope of license renewal in error and that only the piping and valves for the building heat system located in the reactor building perform a secondary containment function. Valves 1-1029, 1-1030, 2-1318, 2-1319, 3-1386, and 3-1387 are located in the turbine building and, therefore, are not within the scope of license renewal. The applicant also stated that drawing 0-47E866-1-LR has been revised to show the boundary ending at the reactor building wall and will be resent as part of the annual update.

Based on its review, the staff found the applicant's response to RAI 2.3.3.15-1 acceptable. Valves 1-1029, 1-1030, 2-1318, 2-1319, 3-1386, and 3-1387 do not perform an intended function in accordance with the requirements of 10 CFR 54.4(a) and are outside the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.15-1 is resolved.

2.3.3.15.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the building heat system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the building heat system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.16 Raw Water Chemical Treatment System

2.3.3.16.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.16, the applicant described the raw water chemical treatment system. The raw water chemical treatment system prevents bio-fouling of systems, including the EECW and RHRSW systems, that use water directly from Wheeler Reservoir. The raw water chemical treatment system provides the capability to inject a biocide into the fluid stream.

The raw water chemical treatment system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the raw water chemical treatment system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides for pressure boundary integrity to the RHRSW and EECW systems
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.16, the applicant identified the following raw water chemical treatment system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, restricting orifice, and valves.

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and UFSAR Sections 10.7.3, 10.8.4, and 10.10.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.3.16.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the raw water chemical treatment system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the raw water chemical treatment system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Demineralizer Backwash Air System

2.3.3.17.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.17, the applicant described the demineralizer backwash air system. The demineralizer backwash air system is a plant-shared system that supplies a high volume of low pressure air for purpose of backwashing plant demineralizers. In addition, the system supplies the condensate demineralizers in the turbine building and penetrates the secondary containment to supply the reactor water cleanup (RWCU) and fuel pool cooling and cleanup (FPC) demineralizers in the reactor building. The demineralizer backwash air system is in standby operation during normal operation and is operated manually, when required, for backwashing of the demineralizers.

The demineralizer backwash air system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the demineralizer backwash air system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.17, the applicant identified the following demineralizer backwash air system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, traps, and valves.

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17 and UFSAR Section 5.3.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.3.17.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the demineralizer backwash air system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the demineralizer backwash air system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Standby Liquid Control System

2.3.3.18.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.18, the applicant described the SLC system. The SLC system provides a backup method, independent of the control rods, to make the reactor subcritical over the full range of operating conditions. The SLC system can be manually initiated from the main control room to pump a boron neutron absorber solution into the reactor. This function is initiated if the operator determines that the reactor cannot be shut down or kept shut down with the control rods alone. During normal operation, the SLC system is in standby and must be manually initiated, if required.

The SLC system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the SLC system could prevent the satisfactory accomplishment of an SR function. In addition, the SLC system performs functions that support ATWS.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides a primary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.18, the applicant identified the following SLC component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, piping, RCPB piping, pumps, tanks, tubing, valves, and RCPB valves.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 and UFSAR Sections 3.8, 5.2.3, and 7.19 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.18, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.18-1, the staff stated that component electric heaters, located inside the SLC tank, are shown on license renewal drawings 1-47E854-1-LR, 2-47E854-1-LR, and 3-47E854-1-LR as subject to an AMR. However, LRA Section 2.3.5 lists the component UNID of the heater in three different component types (fittings, heaters, or tanks). Therefore, the staff requested that the applicant identify which component type in LRA Table 2.3.3.18 includes the electric heater. Furthermore, during a telephone conference on October 7, 2004, the staff requested that the applicant justify the exclusion of a strainer, addressed in UFSAR Section 3.8.3 but not depicted on the license renewal drawings or included in LRA Table 2.3.3.18, from the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that this heater is included in the component type "fittings" in LRA Table 2.3.3.18. The staff requested the applicant to verify that the heaters are, in fact, included in the component type "fittings." In a supplemental response, dated June 9, 2005, the applicant confirmed that the heaters are included in component type "fittings" in LRA Table 2.3.3.18 and are so documented in the

Standby Liquid Control System Report. The applicant also provided information that the strainers have been included in LRA Table 2.3.3.18 for being subject to an AMR.

Based on its review, the staff found the applicant's response to RAI 2.3.3.18-1 acceptable. It clarifies that the heater is included in the component type "fittings" in the LRA table, and it includes the strainer within the scope of license renewal and subject to an AMR. Therefore, the staff's concerns described in RAI 2.3.3.18-1 and the October 7, 2004, telephone discussion are resolved.

In order to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1, the applicant expanded the system boundaries for the standby liquid control system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted its review result of the documentation of the seismic Class I qualification to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to safety-related piping or components. In its February 28, 2005 letter, enclosure 2, "Mechanical Systems," the applicant stated that additional piping and components had been added to the scope of the standby liquid control system. However, the component types do not differ from those listed LRA Table 2.3.3.18; therefore, no changes to the standby liquid control system portion in the LRA are required.

The staff reviewed the NSR piping up to first equivalent anchor point of seismic Class I piping boundaries and found the expanded scope of components to be acceptable on the basis that the applicant had adequately identified all SLC NSR components that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.18.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the SLC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the SLC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Off-Gas System

2.3.3.19.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.19, the applicant described the off-gas system. Each unit has a separate off-gas system, which includes subsystems that process and dispose of the gases produced during normal operation from the main condenser steam jet air ejectors, the startup condenser vacuum pumps, the condensate drain tank vent, and the steam packing exhauster. The gases are processed to minimize any release of harmful radioactivity and are then diverted to the plant stack for dilution and release to the atmosphere at elevation. Backdraft dampers limit the amount of radioactive release at ground level during accidents that require operation of the SGT system.

The off-gas system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- provides flow path integrity for the release of the filtered SGT system gases to the stacks
- provides automatic closure of back-draft prevention dampers to prevent back-flow and potential ground-level release of radiation
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.19, the applicant identified the following off-gas system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fittings, and piping.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and UFSAR Sections 1.6.1.1.10, 1.6.1.4.4, 5.3.3, 7.12.2, 7.12.3, 9.5, 11.4, 14.6.3.6, and F.7.14 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1, the applicant expanded the system boundaries for the off-gas system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components. In the February 28, 2005 letter, enclosure 2, “Mechanical Systems,” the applicant stated that additional components, valves, had been added to the scope of the off-gas system. The component type valve was added to LRA Table 2.3.3.19.

The staff reviewed the NSR piping up to first equivalent anchor point of seismic Class I piping boundaries and found the expanded scope of components to be acceptable on the basis that the applicant had adequately identified all SLC NSR components that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.19.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the off-gas system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the off-gas system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.20 Emergency Equipment Cooling Water System

2.3.3.20.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.20, the applicant described the EECW system. The EECW system is a plant-shared system, which has two headers that use dedicated RHRSW pumps to supply water from the Wheeler Reservoir into heat exchangers. The heat exchangers cool equipment including the DG engine coolers, CS pump room coolers, RHR pump seal coolers and room coolers, control bay chillers, hydrogen and oxygen containment gas analyzers, and electric board room chillers. The EECW system provides cooling water to equipment that is essential for safe shutdown and a backup cooling water supply to the reactor building closed cooling water heat exchangers.

The EECW system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the EECW system could prevent the satisfactory accomplishment of an SR function. In addition, the EECW system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides cooling water to the HVAC system chillers, RHR system pump seal coolers, containment inerting system hydrogen and oxygen gas analyzers, DG, RHR and CS equipment room coolers, and FPC system
- provides an EECW valve position interlock signal for automatic start of the RHRSW pumps
- provides a secondary containment boundary
- prevents debris from entering a system or component
- provides for flow distribution
- provides for heat transfer

- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.20, the applicant identified the following EECW system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, flexible connectors, heat exchangers, piping, restricting orifice, strainers, tubing, and valves.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Sections 5.3, 7.18, 10.10, and F.7.17 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.20, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.20-1, the staff stated that License renewal drawings 1-47E859-1-LR, 2-47E859-1-LR, and 3-47E859-1-LR depict the EECW system. The cooling water return piping from the SR components terminates at locations designated as "yard drainage." LRA Table 3.3.2.20 indicates that buried carbon and low-alloy steel piping has been evaluated for aging management. However, neither the LRA nor the associated drawings adequately identify the extent of the buried piping subject to an AMR. Therefore, the staff requested that the applicant identify the extent of the buried piping and provide an appropriately marked license renewal drawing, or identify a specific structure where the piping subject to an AMR terminates. The staff also requested that the applicant justify the exclusion of any buried piping or structures between the emergency equipment cooling water system and the final discharge structure from the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that a note had been added to license renewal drawings 1-47E859-1-LR, 2-47E859-1-LR, and 3-47E859-1-LR to state that the EECW buried piping is within the scope of license renewal up to the catch basins shown on isometric drawing 0-17W300-9.

Based on its review, the staff found the applicant's response to RAI 2.3.3.20-1 acceptable. It adequately identifies the extent of the buried emergency equipment cooling water piping that is within the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.20-1 is resolved.

2.3.3.20.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the EECW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the EECW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.21 Reactor Water Cleanup System

2.3.3.21.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.21, the applicant described the RWCU system. A separate RWCU system is provided for each unit. The major equipment for the RWCU system is located in the reactor building and consists of two pumps, regenerative and non-regenerative heat exchangers, and two filter/demineralizers with supporting equipment. Suction for the system is taken from the reactor vessel bottom drain and from the RHR system shutdown cooling suction line, which is supplied by the reactor coolant recirculation system. The system automatically isolates upon accident initiation and upon SLC system actuation. The RWCU system functions to maintain a high reactor-water purity to limit corrosion, chemical interactions, fouling, and deposits on reactor heat transfer surfaces. The system also removes corrosion products to limit impurities available for activation by neutron flux and the resultant radiation from deposits of corrosion products. In addition, the system provides a means for removal of water from the reactor vessel during normal operations.

The RWCU system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the RWCU system could prevent the satisfactory accomplishment of an SR function. In addition, the RWCU system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides RCPB
- provides system pressure boundary support (check valve) to HPCI to prevent diversion of HPCI system core cooling water from the reactor vessel (Unit 3 only)
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.21, the applicant identified the following RWCU system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, heat exchangers, piping, RCPB piping, pumps, restricting orifice, strainers, tanks, traps, tubing, valves, and RCPB valves.

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21 and UFSAR Sections 3.8, 4.1, 4.9, 5.2.3, 5.3, and 7.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.21, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant’s scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.21-1, the staff identified thermal tees that are within the scope of license renewal and subject to an AMR. However, “thermal tees” is not a component type listed in LRA Table 2.3.3.21-1 as being subject to an AMR, nor it is included in LRA Section 2.3.5 as a component type. Therefore, the staff requested that the applicant indicate if thermal tees are already included in LRA Table 2.3.3.21 as a component type subject to an AMR, or justify the exclusion of the components from being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response, by letter dated April 28, 2005, the applicant stated that thermal tees are included in LRA Table 2.3.3.21 as component type “fittings.” Thermal tees were not listed in LRA Section 2.3.5, because these components are not assigned UNID’s on drawings. LRA Section 2.3.5 was generated to show where UNID’s appearing on the license renewal drawings were grouped in a component type.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.21-1 acceptable. because thermal tees are included as a component type that is subject to an AMR. Therefore, the staff’s concern described in RAI 2.3.3.21-1 is resolved.

In RAI 2.3.3.21-2, the staff identified fusible plugs (FUPG) to be within the scope of license renewal and subject to an AMR. The drawing note associated with FUPGs states that the FUPG is a threaded pipe plug with a low temperature eutectic alloy that is attached to the RWCU pipe upstream of valve FCV-69-94. Eutectic material melts on high temperature, venting the control air line, which closes isolation valve FCV-69-94. Also, another drawing note states that the system shall be qualified for an elevated temperature excursion up to 562°F during an Appendix R event from the non-generative heat exchanger outlet to valve FCV-69-94.

a. The FUPGs are neither listed in LRA Table 2.3.3.21 as a component type subject to an AMR, nor as a subcomponent of the component types listed in LRA Section 2.3.5. Therefore, the staff requested that the applicant indicate if FUPGs are already included in LRA Table 2.3.3.21 as a component type subject to an AMR, or justify the exclusion of these components from being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

b. Based on the above mentioned drawing notes, it appears that valve FCV-69-94 satisfies criterion 10 CFR 54.4(a)(3) for an EQ and fire protection regulated event. However, the piping and components associated with this valve, including the above-mentioned FUPG, are shown as within the scope of license renewal in accordance with the 10 CFR 54.4(a)(2) criterion. The staff requested that the applicant explain how valve FCV-69-94 functions differently from its associated pipeline.

In its response, by letter dated April 28, 2005, the applicant stated that the FUPGs were inadvertently colored in blue on the drawing but should have been black since they are active components and are not within the scope of license renewal. The applicant also stated that the fusible plugs do not form a pressure boundary function for the RWCU system. The license renewal drawings have been revised to show FUPG-32-5105 black instead of blue, since it is not subject to an AMR.

Based on its review, the staff found the applicant's response to RAI 2.3.3.21-2a acceptable. FUPGs meet the definition for an active component and, therefore, are not subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.21-2a is resolved.

With regard to RAI 2.3.3.21-2b, the applicant stated that the piping and equipment downstream of FCV-69-2 up to and including valve FCV-69-94 will be corrected on the drawings to show the components in scope per the criteria 10 CFR 54.4a(3) and subject to an AMR, since these components form the reactor coolant pressure boundary during an Appendix R event. The tube side of the heat exchanger is considered part of the reactor coolant pressure boundary while the shell side provides the structural support for the tubes. Shell side piping connections will remain in scope. Also, System 43 in drawing 0-105E3156-1-LR will be corrected to show its components required for pressure boundary integrity in red instead of blue on the drawing, that are within the scope of license renewal and subject to an AMR, due to its interface with RWCU drawings 2-47E810-1-LR and 3-47E810-1-LR.

Based on its review, the staff found the applicant's response to RAI 2.3.3.21-2b acceptable. The applicant clarified the function of the piping and valve in question and corrected the corresponding drawings to reflect the appropriate intended function of the components. Therefore, the staff's concern described in RAI 2.3.3.21-2b is resolved.

In RAI 2.3.3.21-3, the staff stated that UFSAR (Revision 20), Section 4.9 states that:

> Reactor coolant is continuously removed from the reactor coolant recirculation system, cooled in the regenerative and non-regenerative heat exchangers, filtered and demineralized, and returned to the feedwater system through the

shell side of the regenerative heat exchanger. The Unit 3 RWCU system has the capability to return process fluid to the feedwater system through both reactor feedwater lines A and B. The Unit 2 RWCU system only has one return line through reactor feedwater line B.

Only, the RWCU system return line to the reactor feedwater line B is depicted on license renewal drawing 3-47E810-1-LR. Therefore, the staff requested that the applicant indicate whether feedwater line A is within the scope of license renewal and subject to an AMR, or provide an explanation for its exclusion. The staff also asked the applicant to provide an alternative drawing that shows the RWCU system return to feedwater line A for Unit 3.

In its response, by letter dated April 28, 2005, the applicant stated that the Unit 3 RWCU system return to feedwater line A is shown on license renewal drawing 3-47E810-1-LR (at location G6). The applicant further noted that the return is through a HPCI line shown on 3-47E812-1-LR (location E6) which connects to feedwater line A shown on 3-47E803-1-LR (location G6). The HPCI and feedwater portions of this return path are within the scope of license renewal.

Based on its review, the staff found the applicant's response to RAI 2.3.3.21-3 acceptable. The applicant identified the return to feedwater line A and stated that it is within the scope of license renewal as indicated on the provided license renewal drawings. Therefore, the staff's concern described in RAI 2.3.3.21-3 is resolved.

In RAI 2.3.3.21-4, the staff identified flow indicators FI-85-75 and FI-85-77, and flow element FE-69-13 as excluded from the scope of license renewal. The flow indicators and flow element serve an intended function of pressure boundary and are passive and long-lived components. It is noted that similar flow indicators and flow elements on drawings 2-47E810-1-LR and 3-47E810-1-LR are shown to be within the scope of license renewal and subject to an AMR. However, "flow indicators" is not listed in LRA Table 2.3.3.21 as a component type subject to an AMR, nor as a subcomponent of the component types listed in LRA Section 2.3.5. Therefore, the staff requested that the applicant:

a. Justify the exclusion of the aforementioned flow indicators and flow element in Unit 1 from the scope of license renewal and from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

b. Clarify whether flow indicators are included in other component types already listed in LRA Table 2.3.3.21, or justify their exclusion from an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In its response, by letter dated April 28, 2005, the applicant stated that NEI 95-10, Appendix B indicates that flow indicators are active components. FI 85-75 and FI 85-77 were colored blue in error on license renewal drawings 2-47E810-1-LR and 3-47E810-1-LR, but have been corrected to show these components black on the drawings; that is, not subject to an AMR. The flow element on license renewal drawing 1-47E810-1-LR was included as a fitting in the evaluation but was inadvertently not colored blue on the drawing. License renewal drawing 1-47E810-1-LR has also been revised to show that FE 69-13 is within the scope of license renewal and subject to AMR.

With regard to RAI 2.3.3.21-4b, the applicant stated that “flow indicators” is not a component type listed in LRA Table 2.3.3.21. Flow indicators were excluded from an AMR based on guidance provided in NEI 95-10 Appendix B.

On the basis of this review, the staff was unable to find the applicant’s response to RAI 2.3.3.21-4 acceptable. The applicant follows the guidance in NEI 95-10, which lists flow indicators as active components. However, the flow indicators in question are in-line indicators. The indicator portion of the component is an active component, but the piping portion of the indicator through which reactor water flows provides a pressure boundary function. Therefore, this portion of the component should be within the scope of license renewal and subject to an AMR. In a follow-up question, the staff asked the applicant to justify the exclusion of the piping portion of the flow indicators.

In a follow-up response, by letter dated May 24, 2005, the applicant stated that the pressure boundary portion of the flow indicators are in scope and are evaluated as fittings in the CRD system (system 85). License renewal drawings 1-47E810-1-LR, 2-47E810-1-LR, and 3-47E810-1-LR were revised to show that FI-75 and FI-77 are in scope and subject to an AMR for meeting the10 CFR 54.4(A)(2) criterion. The pressure retaining portion of the flow indicators are stainless steel with internal environment of treated water, with external environment of inside air, and are already contained in LRA Table 3.3.2.29. The applicant further stated that all license renewal drawings were reviewed for in-line flow indicators that provide a pressure boundary function. This review identified the drawings for systems 43, 68, 69, and 74 that contain flow indicators with pressure boundary functions. The applicant stated that no changes to LRA tables are required since fittings contain the material and environment combinations for the in-line flow indicators, flow indicating controllers, and flow indicating switches that provide a pressure boundary function.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.21-4 acceptable. The applicant included the flow indicators within the scope of license renewal and subject to an AMR. The applicant also performed a review for all other mechanical systems and identified the systems with flow indicators that form a pressure boundary. The applicant revised the system drawings accordingly by adding these flow indicators in scope. Therefore, the staff’s concern described in RAI 2.3.3.21-4 is resolved

In RAI 2.3.3.21-5, the staff identified a 4-inch pipeline to the waste collector and surge tank inside the pipe tunnel to radwaste (location B4) excluded from the scope of license renewal. However, the same pipeline on the license renewal drawing is shown as being within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). Therefore, the staff requested that the applicant clarify this apparent discrepancy.

In its response, by letter dated April 28, 2005, the applicant stated that the line was inadvertently colored in blue but should have been in black. The drawing was corrected to show the line in black, that is, not within the scope of license renewal.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.21-5 acceptable. The applicant clarified that the piping in question is not within the scope of license renewal and corrected the corresponding drawing. Therefore, the staff’s concern described in RAI 2.3.3.21-5 is resolved.

2.3.3.21.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RWCU system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RWCU system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.22 Reactor Building Closed Cooling Water System

2.3.3.22.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.22, the applicant described the reactor building closed cooling water system. The reactor building closed cooling water system provides a continuous supply of cooling water during normal operation to designated plant equipment located in the primary and secondary containments. Water cooled in the heat exchangers provides cooling water for components such as the reactor recirculation system pumps and motor, the RWCU system pumps and non-regenerative heat exchanger, the fuel pool cooling and cleanup system heat exchanger, the drywell atmosphere cooling coils, the reactor building equipment drain sump heat exchanger, the drywell equipment drain sump heat exchanger, the drywell air compressors and aftercoolers, and the sample coolers in the sampling and water quality system. The system is normally operational and will automatically trip if an accident initiates it.

The reactor building closed cooling water system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the reactor building closed cooling water system could prevent the satisfactory accomplishment of an SR function. In addition, the reactor building closed cooling water system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides for a pressure boundary of the reactor building closed cooling water system components connected to the control air system that must maintain the boundary in support of supplying CAD to the MSRVs
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.22, the applicant identified the following reactor building closed cooling water system component types that are within the scope of license renewal and subject to an

AMR: bolting, fittings, flexible connectors, heat exchangers, piping, pumps, strainers, tanks, tubing, and valves.

As a result of the review of seismic Class I piping boundaries to identify supports and equivalent anchors in response to RAI 2.1-2A(3) (discussed in SER Section 2.1), the applicant expanded the system boundaries for the reactor building closed cooling water system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports and equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components. In its February 28, 2005, letter, enclosure 2, “Mechanical Systems,” the applicant stated that additional piping and components had been added to the scope of the reactor building closed cooling water system. However, the component types do not differ from those listed in LRA Table 2.3.3.22 and no changes to the reactor building closed cooling water system portion of the LRA are required.

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22 and UFSAR Sections 5.2, 5.3, 10.6, and F.6.19 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.22, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant’s scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.22-1, the staff stated that license renewal drawings 2-47E610-70-1-LR and 3-47E610-70-1-LR show that the flow control valves and the combination of air filter/pressure regulators for the drywell atmospheric cooling units (A5 and B5) are within the scope of license renewal and subject to an AMR. However, the flow control valves and combination of the air filter/pressure regulators for the drywell atmospheric cooling units A4 and B4, A3 and B3, A2 and B2, and A1 and B1 are not identified as being within the scope of license renewal. Therefore, the staff requested that the applicant justify the exclusion of the flow control valves and combination air filter/pressure regulators for the drywell atmospheric cooling units A4 and B4, A3 and B3, A2 and B2, A1 and B1 components from the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that the air filter/pressure regulators for drywell atmospheric cooling units A1 and B1, A2 and B2, A3 and B3, and A4 and B4 are not within the scope of license renewal, because they do not form a pressure boundary with the control air system (system 32).

Based on its review, the staff was unable to find the applicant's response to RAI 2.3.3.22-1 acceptable, because a drawing note (Note 6 at location F2 on license renewal drawings 2-47E610-70-1-LR and 3-47E610-70-1-LR) states:

> The cooling water enters the drywell, supplying two drywell atmospheric cooling units (A and B). Each Cooling Unit has five cooling coils, four operating and one spare. Control is from the main control room by a hand switch (HS-70-16A, etc) which operates dampers and diaphragm-operated gate valves (FCV-70-16, etc). Each drywell cooling unit has five fans, any four of them may be used at one time and the fifth reserved as a spare.

Any cooling unit can be used as a spare unit, and the configuration shown on the license renewal drawings for cooling units A5 and B5 can be applied to all other cooling units. Hence, cooling units A1 through A4 and B1 through B4 also form a pressure boundary with the control air system when they are used as a spare unit. Therefore, the air filter/pressure regulators for cooling units A1 through A4 and B1 through B4 should be within the scope of license renewal and subject to an AMR. Considering the above-mentioned drawing note, the staff asked in a supplemental RAI that the applicant justify the exclusion of cooling units A1 through A4, and B1 through B4 from the scope of license renewal and from being subject to an AMR.

In a supplemental response dated June 9, 2005, the applicant stated that, based upon further review, the filter/pressure regulators for cooling units A1 through A4, and B1 through B4 will be included within the scope of license renewal, and that the license renewal drawings will be revised accordingly.

Based on its review, the staff found the applicant's response to RAI 2.3.3.22-1 acceptable. The applicant added the filter/pressure regulators for cooling units A1 through A4, and B1 through B4 to the scope of license renewal and will correct the corresponding drawings. Therefore, the staff's concern described in RAI 2.3.3.22-1 is resolved.

In RAI 2.3.3.22-2, the staff stated that the operators of the two valves FCV 70-24 and FCV 70-34 are shown on license renewal drawings 2-47E610-70-1 and 3-47E822-1 as being within the scope of license renewal and subject to an AMR. However, license renewal drawings 3-47E610-70-1, 1-47E822-1-LR, and 2-47E822-1-LR show the operators for the same valves as not within the scope of license renewal and not subject to an AMR. T, the staff requested that the applicant clarify the inconsistency and justify the exclusion of operators for FCV 70-24 and FCV 70-34 from the scope of license renewal and from being subject to an AMR.

In its response, by letter October 19, 2004, the applicant stated that the operators shown on drawings 3-47E610-70-1-LR and 2-47E822-1-LR should have been highlighted, (i.e., that they are in scope and subject to an AMR). The applicant further stated that the modification identified in Appendix F.2 had not been implemented in Unit 1; therefore, these components are not within the scope of license renewal for Unit 1. Drawings 3-47E610-70-1-LR and 2-47E822-1-LR have been revised and will be sent to the staff as part of the annual update.

Based on its review, the staff found the applicant's response to RAI 2.3.3.22-2 acceptable. It concurs that the operators addressed in the RAI should be within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.22-2 is resolved.

In RAI 2.3.3.22-3, the staff noted that LRA Section 2.3.3.22 states that the operators for the dampers are within the scope of license renewal as a pressure boundary for the control air. With regard to this statement, the staff requested the following information:

a. The UNIDs assigned to various components, in particular, the dampers and the operators for the dampers, are for the reactor building closed cooling water system. Therefore, the staff requested that the applicant clarify whether or not the operators for the dampers are evaluated in the control air system.

b. The staff also asked the applicant whether the operators shown on license renewal drawings 2-47E610-70-1-LR and 3-47E610-70-1-LR are subject to an AMR and, if so, under what component type.

In its response, by letter dated October 19, 2004, the applicant stated the following:

a. The damper operators are part of the reactor building closed cooling water system, and are evaluated as valves in the reactor building closed cycle cooling water system. As depicted on license renewal drawings 2-47E610-70-1-LR and 3-47E610-70-1-LR, the damper operators support the control air system (system 32) pressure boundary. Since these damper operators are connected to the control air system, they must maintain a pressure boundary in order for the control air system to maintain its system boundary (i.e., form a pressure boundary). Therefore, any damper operators that are required to form a pressure boundary with the control air system are within the scope of license renewal for the control air system.

Based on its review, the staff found the applicant's response to RAI 2.3.3.22-3a acceptable. It clarifies that the damper operators have a pressure boundary intended function and are within the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.22-3a is resolved.

In its response, by letter dated October 19, 2004, the applicant further stated the following:

b. The damper operators are subject to an AMR and are included as part of the component type "valves" in LRA Table 2.3.3.22.

Based on its review, the staff found the applicant's response to RAI 2.3.3.22-3b acceptable. It confirms that the damper operators are subject to an AMR and are included in LRA Table 2.3.3.22. Therefore, the staff's concern described in RAI 2.3.3.22-3b is resolved.

The staff also reviewed the results of the applicant's review of seismic Class I piping boundaries provided in the applicant's letter, dated February 28, 2005, enclosure 2, to identify supports and equivalent anchor points in response to RAI 2.1-2A(3). The staff found the expanded scope of components to be acceptable on the basis that the applicant had adequately identified all reactor building closed cooling water system NSR components that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.22.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor building closed cooling water system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor building closed cooling water system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.23 Reactor Core Isolation Cooling System

2.3.3.23.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.23, the applicant described the RCIC system. The RCIC system provides makeup water to the reactor vessel during shutdown and also provides isolation from the main heat sink to supplement or replace the normal makeup water sources. The system also includes associated valves and piping capable of delivering makeup water to the reactor vessel. During normal operation, the system is in standby and initiates, automatically, when required. The RCIC system has automatic isolation provisions to ensure the integrity of the primary containment.

The RCIC system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the RCIC system performs functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides primary and secondary containment boundaries
- provides for a system pressure boundary in support of the residual heat removal system containment (torus) cooling function
- establishes MSIV leakage pathway to the condenser
- provides sufficient reactor coolant makeup to maintain the reactor in a safe condition
- provides debris protection
- restricts flow
- provides for heat transfer
- provides mechanical closure

- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.23, the applicant identified the following RCIC system component types that are within the scope of license renewal and subject to an AMR: bolting, condenser, expansion joint, fittings, RCPB fittings, flexible connector, heat exchangers, piping, RCPB piping, pumps, restricting orifice, RCPB restricting orifice, strainers, tanks, traps, tubing, turbines, valves, and RCPB valves.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23 and the UFSAR Sections 4.1, 4.7, 5.2.3, 5.3, 7.3, and 7.18 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.23, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.23-1, the staff stated that UFSAR Section 4.7.5, states that the RCIC makeup water is delivered into the reactor vessel through a connection to the feedwater line and is distributed within the reactor vessel through the feedwater sparger. The connection to the feedwater line is provided with a thermal sleeve. It is further stated that the thermal sleeve (liner) in the feedwater line is designed as a nonpressure-containing liner and is provided to protect the pressure-containing piping tee from excessive thermal stress. In LRA Table 2.3.3.23, thermal sleeve (liner) was not identified as a component type within the scope of license renewal. Therefore, the staff requested the applicant to include this component type within the scope of license renewal and AMR.

In its response, by letter dated November 3, 2004, the applicant stated that the material for this component was identified as pipe and pipe fitting in the feedwater system and will be inspected as part of the One-Time Inspection Program.

Based on its review, the staff found the applicant's response to RAI 2.3.3.23-1 acceptable. The applicant included the subject component and its intended functions within the scope requiring an AMR. Therefore, the staff's concern described in RAI 2.3.3.23-1 is resolved.

2.3.3.23.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RCIC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RCIC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.24 Auxiliary Decay Heat Removal System

2.3.3.24.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.24, the applicant described the auxiliary decay heat removal (ADHR) system. The ADHR system can be used to remove residual heat from the spent fuel pool and reactor cavity during outages. The ADHR system supplements the fuel pool cooling and cleanup system and consists of two cooling water loops. The primary cooling loop circulates water from the spent fuel pool entirely inside the reactor building and rejects heat from the spent fuel pool to a secondary loop via a heat exchanger. The secondary loop transfers heat to the atmosphere outside of the reactor building by the means of evaporative cooling towers.

The ADHR system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the ADHR system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.24, the applicant identified the following ADHR system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, heat exchangers, piping, pumps, strainers, tubing, and valves.

2.3.3.24.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.24 and UFSAR Sections 5.3, 10.5, and 10.22 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1, the applicant expanded the system boundaries for the ADHR system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports and equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the 10 CFR 54.4(a)(2) cases where NSR piping or components are directly connected to SR piping or components. In its February 28, 2005, letter, enclosure 2, “Mechanical Systems,” the applicant stated that additional piping and components had been added to the scope of the ADHR system; however, the component types do not differ from those listed in LRA Table 2.3.3.24 and no changes to the ADHD system portion of the LRA are required.

The staff reviewed the NSR piping up to first equivalent anchor point of seismic Class I piping boundaries and found the expanded scope of components to be acceptable on the basis that the applicant had adequately identified all SLC NSR components that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.24.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the ADHR system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the ADHR system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.25 Radioactive Waste Treatment System

2.3.3.25.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.25, the applicant described the radioactive waste treatment system. The radioactive waste treatment system is comprised of subsystems that process solid and liquid radwaste that is generated during normal plant operation. The subsystems are plant-shared systems.

The radioactive waste treatment system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the radioactive waste treatment system could prevent the satisfactory accomplishment of an SR function. In addition, the radioactive waste treatment system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides piping interface integrity with the SGT system and the off-gas system in support of the release of filtered SGT gases through the stack
- provides a pressure boundary of the radioactive waste treatment system components connected to the control air system that must maintain a pressure boundary in support of supplying CAD to the MSRVs
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.25, the applicant identified the following radioactive waste treatment system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, heat exchangers, piping, pumps, restricting orifices, tanks, strainers, tubing, and valves.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 and UFSAR Sections 4.10, 5.2, 5.3, 9.1, 9.2, 9.3, 9.5, 10.16, F.6.7, F.6.8, F.6.20, and F.7.14 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues regarding NSR piping segments that support secondary containment discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1, the applicant expanded the system boundaries for the radioactive waste treatment system. By letter dated May 31, 2005, the applicant submitted the NSR piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to its letter dated May 31, 2005, the applicant stated that additional piping had been added to scope. However, the component type does not differ from those listed in LRA Table 2.3.3.25; therefore, no changes to the radioactive waste treatment system portion of the LRA are required.

The applicant also expanded the system boundaries for the radioactive waste treatment system to resolve seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the (a)(2) cases where NSR piping or components are directly connected to SR piping or components. In its February 28, 2005 letter, enclosure 2, “Mechanical Systems,” the applicant stated that additional piping and components were added to the scope in the cleanup decant pump room in the radwaste building. The component types do not differ from those listed in LRA Table 2.3.3.25; therefore, no changes to the radioactive waste treatment system portion of the LRA are required. In its response, the applicant explained that notes had been added to the radioactive waste treatment drawing to clarify that embedded piping is in scope for anchorage when attached to non-embedded in-scope piping and all the piping between the embedded piping and in-scope non-embedded piping is within the scope of license renewal.

The staff reviewed the results of the applicant’s evaluation of NSR piping segments that support secondary containment in response to RAI 2.1-2A(1) and (2), and the results of the applicant’s evaluation of seismic Class I piping boundaries in its response to RAI 2.1-2A(3). The staff found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.25.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the radioactive waste treatment system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the radioactive waste treatment system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.26 Fuel Pool Cooling and Cleanup System

2.3.3.26.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.26, the applicant described the FPC system. The FPC system removes residual heat from the fuel assemblies and maintains the fuel pool water within the specified temperature limits. The system minimizes corrosion product buildup and controls water clarity in the fuel pool so that the fuel assemblies can be efficiently handled underwater. In addition, the FPC system minimizes fission product concentration in the fuel pool water. The system is in normal operation and additional provisions can be made to prevent siphoning of the fuel pool. A cross-connection exists with the RHR system; the RHR system can provide supplemental cooling, if needed.

The FPC system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the FPC system could prevent the satisfactory accomplishment of an SR function. In addition, the FPC system performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides for pressure boundary integrity at the RHR/FPC interface
- prevents inadvertent siphoning of the spent fuel pool
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.26, the applicant identified the following FPC system component types that are within the scope of license renewal and subject to an AMR: bolting, expansion joint, fittings, heat exchangers, piping, pumps, restricting orifice, tanks, tubing, and valves.

2.3.3.26.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26 and UFSAR Sections 4.8, 5.3, 10.5, 10.17, and 10.22 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the fuel pool cooling and cleanup system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to its letter dated May 31, 2005, the applicant stated that additional piping had been added to scope. However, the component type does not differ from those listed in LRA Table 2.3.3.26; therefore, no changes to the fuel pool cooling and cleanup system portion of the LRA are required.

The applicant also expanded the system boundaries for the FPC system to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, or other qualification documentation to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the (a)(2) cases in which NSR piping or components are directly connected to SR piping or components. In the February 28, 2005 letter, enclosure 2, "Mechanical Systems," the applicant stated that additional piping and components had been added to the scope of the FPC system. However, the component types do not differ from those listed in LRA Table 2.3.3.26; therefore, no changes to the FPC system portion of the LRA are required.

The staff reviewed the results of the applicant's evaluation of NSR piping segments that support secondary containment in response to RAI 2.1-2A(1) and (2), and the results of the applicant's evaluation of seismic Class I piping boundaries in its response to RAI 2.1-2A(3). The staff found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.26.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the FPC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the FPC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.27 Fuel Handling and Storage System

2.3.3.27.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.27, the applicant described the fuel handling and storage system. Each unit is provided with a dry, new fuel storage vault. The new fuel storage racks provide a location in the vaults where new fuel can be stored. The racks are designed to preclude criticality even if the new fuel storage vault is flooded. Each reactor also has a spent fuel storage pool. A transfer canal is provided to join the pools for Units 1 and 2. The spent fuel storage racks provide a location where spent fuel, received from the reactor vessel, can be stored at the bottom of each fuel pool. The racks are full length, top entry, and are designed to maintain the spent fuel in a spatial geometry that precludes the possibility of criticality. The racks are comprised of staggered, stainless-steel container tubes. Each tube wall has a core of Boral sandwiched within stainless steel. Servicing equipment is provided to facilitate refueling, fuel inspection, and fuel maintenance.

The fuel handling and storage system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the fuel handling and storage system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides NSR components that ensure the satisfactory performance of SR components
- provides structural support

In LRA Table 2.3.3.27, the applicant identified the following fuel handling and storage system component types that are within the scope of license renewal and subject to an AMR: bolting and fasteners, fuel preparation machines, and the refueling platform (including the assembly, rails, and main fuel grapple).

2.3.3.27.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.27 and UFSAR Sections 10.2, 10.3, 10.4, and 10.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.27, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI 2.3.3.27-1, the staff stated that LRA Section 2.3.3.27 states that the portions of the fuel handling and storage system that contain components subject to an AMR are the fuel preparation machines, refueling platform (assembly, rails, and the main fuel grapple), and the bolting and fasteners associated with the refueling platform and fuel preparation machines. LRA Table 2.3.3.27 lists components associated with the fuel handling and storage systems that are subject to an AMR. UFSAR Section 10.4 (in Table 10.4-1, "Tools and Servicing Equipment") lists fuel servicing equipment, including general purpose grapple, channel transfer grapple, fuel inspection fixture, and new fuel inspection stand, but none of these are referenced in LRA Section 2.3.3.27. In reviewing LRA Section 2.3.3.27, the staff also found that no drawings are provided for this system. There is insufficient information for the staff to determine whether these components are within the scope of license renewal and subject to an AMR. Therefore, the staff requested that the applicant identify which of these components are within the scope of license renewal and subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated the general purpose grapple, channel transfer grapple, and fuel inspection fixture are within the scope of license renewal; however, an AMR is not required for these components since they are active (i.e., they change configuration). The applicant also stated that the new fuel inspection stand is not SR and does not meet the criterion in 10 CFR 54.4(a)(1). The new fuel inspection stand is also not required for any of the 10 CFR 54.4(a)(3) regulated events. The applicant further stated that the new fuel inspection stand failure would not prevent the accomplishment of an SR intended function of an SR component and does not meet the requirements of 10 CFR 54.4(a)(2).

Based on its review, the staff found the applicant's response to RAI 2.3.3.27-1 acceptable. The applicant had adequately clarifies that the components in question are either active or do not meet any of the requirements of 10 CFR 54.4(a). Therefore, the staff's concern described in RAI 2.3.3.27-1 is resolved.

2.3.3.27.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the fuel handling and storage system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the fuel handling and storage system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.28 Diesel Generator System

2.3.3.28.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.28, the applicant described the diesel generator (DG) system. The DG system is a plant-shared system that consists of four independent DG units, coupled as an alternate independent source of power to four 4160 V shared shutdown boards for Units 1 and 2. There are four additional DG units that provide an alternate independent source of power to four Unit 3 4160 V shutdown boards. The DG system provides an alternate source of power for the ECCS and the safe shutdown systems when the normal power supplies are unavailable. The DGs are normally in standby and can start automatically, when required.

The DG system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the DG system could prevent the satisfactory accomplishment of an SR function. In addition, the DG system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- starts standby AC power source for the 4kV system
- provides power to the 4kV system upon DG availability and loss of offsite power
- provides DG power to diesel fuel transfer pumps
- provides debris protection
- provides for heat transfer

- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.28, the applicant identified the following DG system component types that are within the scope of license renewal and subject to an AMR: bolting, ductwork, fan housings, fittings, flexible connectors, heat exchangers, heaters, piping, pumps, silencer, strainers, tanks, tubing, valves, and RCPB valves.

2.3.3.28.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.28 and UFSAR, Sections 7.4, 7.18, 8.4, 8.5, 8.10, and F.7.9 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.28, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.28-1, the staff identified two components (governor and drain pan) in the DG lube oil subsystem that are not subject to an AMR; however, the piping into and out of these components is subject to an AMR. Therefore, the staff requested that the applicant justify the exclusion of the subject components from within the scope of license renewal and an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that the governor is a controller that is an active component based on components listed in Appendix B of NEI 95-10, Revision 3, and does not require an AMR. With regard to the drain pan, the applicant stated that the drain pan is not within the scope of license renewal since it does not perform a 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3) function. The drain pan would also not be in scope for 10 CFR 54.4(a)(2) since it is not normally fluid-filled and does not present a spray hazard. During a teleconference on May 11, 2005, the applicant clarified that the drain pan is attached to the DG frame and is not in any way attached to or functionally associated with the lube oil system. Its only purpose is to collect any spillage during maintenance when replacing the oil filter. Additionally, the piping, valves, and fittings attached to the drain pan, as shown in the license renewal drawings 0-47E861-5-LR through 0-47E861-8-LR and 3-47E861-5-LR through 3-47E861-8-LR, were inadvertently colored as being within the scope of license renewal and subject to an AMR. These drawings have been revised to reflect that these valves, piping, and fittings are not within the scope of license renewal and not subject to an AMR. The changes will be incorporated in the next annual update.

Based on its review, the staff found the applicant's response to RAI 2.3.3.28-1 acceptable. It justified the exclusion of the governor from an AMR. The applicant also clarifies that the piping, valves, and fittings attached to the drain pan had been colored inadvertently and that the drain pan does not perform a license renewal intended function per 10 CFR 54.4. Therefore, the staff's concern described in RAI 2.3.3.28-1 is resolved.

2.3.3.28.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the DG system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the DG system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.29 Control Rod Drive System

2.3.3.29.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.29, the applicant described the CRD system. The CRD system provides reactivity control by allowing positioning of the control rods at a controlled rate during normal operation; providing scram and diverse scram functions to ensure rapid shutdown, when required; limiting the rod drop rate to minimize the consequences of a rod drop accident; and limiting a rod ejection accident.

From the hydraulic control units, the portions of the system that are subject to an AMR extend to, and from, each control rod housing. From the hydraulic control units, the portions of the system that are subject to an AMR extend to, and then include, the scram discharge volume and associated components. From the hydraulic control units, portions of the system subject to an AMR extend to an interconnection with the RWCU system. The CRDs themselves are short-lived components and, hence, are not subject to an AMR; however, the CRD housing support is subject to an AMR and is included in the component supports commodity group, which is discussed in another section of this SER.

The CRD system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the CRD system could prevent the satisfactory accomplishment of an SR function. In addition, the CRD system performs functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides RCPB
- provides housing support to keep the rods in place
- limits the rod drop rate to less than 3.11 feet per second
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.29, the applicant identified the following CRD system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, heat exchangers, piping, RCPB piping, pumps, restricting orifice, rupture disk, strainers, RCPB strainers, tanks, tubing, valves, and RCPB valves.

2.3.3.29.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.29 and UFSAR Sections 3.4, 3.5, 3.7, 5.2.3, 5.3, 7.7, 7.19, and F.7.12 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.3.29.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the CRD system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the CRD system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.30 Diesel Generator Starting Air System

2.3.3.30.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.30, the applicant described the DG starting air system. The DG starting air system starts the DGs when required. Each DG has an independent starting air system. Each system has two independent subsystems that are both capable of starting their respective DG. Each subsystem consists of an air compressor with associated filters and coolers, and a bank of air receivers. The air compressors operate automatically to maintain the receivers in a pressurized state. The DG starting air system is located in the DG buildings.

The DG starting air system contains SR components that are relied upon to remain functional during, and following, DBEs. In addition, the DG starting air system performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides diesel starting air to the DG system
- provides debris protection
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.30, the applicant identified the following DG starting air system component types that are within the scope of license renewal and subject to an AMR: bolting, diesel air start motor, fittings, flexible connectors, piping, strainers, tanks, tubing, and valves.

2.3.3.30.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.30 and UFSAR Section 8.5.3.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the seismic Class I/II interface issues discussed in RAI 2.1-2A(3) of SER Section 2.1, the applicant expanded the system boundaries for the diesel generator starting air system. By letters dated January 31, 2005, and February 28, 2005, the applicant submitted the results of its review of the seismic Class I qualification documentation to identify the NSR piping, supports/equivalent anchors, or other components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components. In the February 28, 2005 letter, enclosure 2, “Mechanical Systems,” the applicant stated that additional piping and components had been added to scope in association with the outlet filter of the air dryer skid, which is credited as an anchor in the seismic analysis. However, the component types do not differ from those listed in LRA Table 2.3.3.30; therefore, no changes to the diesel generator starting air system portion of the LRA are required. The staff reviewed applicant’s submittals and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.30.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the DG starting air system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the DG starting air system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.31 Radiation Monitoring System

2.3.3.31.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.31, the applicant described the radiation monitoring system. The radiation monitoring system consists of a number of radiation monitors and monitoring systems that are provided on process liquid and gas lines that may serve as discharge routes for radioactive materials.

The radiation monitoring system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the radiation monitoring system could prevent the satisfactory accomplishment of an SR function. In addition, the radiation monitoring system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- provides primary and secondary containment boundaries
- provides system pressure boundary integrity (with all mechanical joints and components associated with the offline liquid monitors) to RHRSW system cooling water for RHR system heat exchangers
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.31, the applicant identified the following radiation monitoring system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, flex hose, piping, pumps, strainers, traps, tubing, and valves.

2.3.3.31.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.31 and UFSAR Sections 5.2.3, 7.12, 7.13, 7.14, 7.15, and F.7.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.31, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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 response.

In RAI 2.3.3.31-1, the staff identified the following monitors as being subject to an AMR:

- gas monitors
- RHR heat exchanger A & C service water discharge radiation monitor
- RHR heat exchanger B & D service water discharge radiation monitor
- raw cooling water radiation monitor
- reactor building closed cooling water radiation monitor

The monitor housing performs a pressure boundary intended function; however, the housing is not listed in LRA Table 2.3.3.31 as a component type subject to an AMR. LRA Section 2.3.5 does not include housing as a part of any component group. Therefore, the staff requested that the applicant clarify whether housings are considered to be part of a component group already listed in LRA Table 2.3.3.31.

In its response, by letter dated October 19, 2004, the applicant stated that the radiation monitor sample chambers (housings) are included as part of the component type "fittings" in LRA Table 2.3.3.31.

Based on its review, the staff found the applicant's response to RAI 2.3.3.31-1 acceptable. It clarifies that the monitor housings are already included in LRA Table 2.3.3.31 in the component type "fittings" as being subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.31-1 is resolved.

In order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the radiation monitoring system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to its letter dated May 31, 2005, the applicant stated that additional components associated with radiation monitor RM 90-250 had been added to scope. However, the component types do not differ from those listed in LRA Table 2.3.3.31; therefore, no changes to the radiation monitoring system portion of the LRA are required. The staff reviewed applicant's submittal and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.3.31.3 Conclusion

The staff reviewed the LRA and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the radiation monitoring system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the radiation monitoring system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.32 Neutron Monitoring System

2.3.3.32.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.32, the applicant described the neutron monitoring system. The neutron monitoring system detects conditions in the core that threaten the overall integrity of the fuel barrier due to excessive power generation. The system also provides signals to the reactor protection system so that the release of radioactive material from the fuel barrier is limited. In addition, the neutron monitoring system provides information for the efficient, expeditious operation and control of the reactor. Conditions that could lead to local fuel damage are detected by the system and used to prevent such damage.

The neutron monitoring system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.3.32, the applicant identified the following neutron monitoring system component types that are within the scope of license renewal and subject to an AMR: bolting and RCPB fittings.

2.3.3.32.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.32 and the UFSAR Sections 3.7 and 7.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in the NRC's 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.32, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.3.32-1, the staff stated that LRA Section 2.3.3.32 states that the average power range monitor subsystem averages the local power range monitor subsystem signals to provide an overall indication of reactor power for control and trip functions. A subsystem of the average power range monitor subsystem, the oscillation power range monitor (OPRM) ensures reactor operation in a stable thermal-hydraulic region. The rod block monitor (RBM) receives input from local power range monitors close to a control rod to prevent fuel damage in the event of a rod withdrawal error. Furthermore, it was stated in the LRA that the portions of the neutron monitoring system that contain components subject to an AMR are only those that form part of the reactor coolant pressure boundary. The staff believes that in addition to the portions that are pressure boundary, OPRM and its functions, as described above, are passive and SR; and hence meet the criteria delineated in 10 CFR 54.4(a)(1) and 10 CFR 54.21(a)(1). Therefore, unless the OPRM is subject to replacement based on a "qualified life" or "specified time period," or degradation of its ability to perform its intended functions due to aging is readily monitorable, the component should be within the scope requiring aging management. Therefore, the staff requested the applicant to provide a justification for why these components are not within the scope of license renewal.

The staff also requested the applicant to provide the basis for excluding other neutron monitoring subsystems in BFN (except portions that perform pressure boundary function) from within the scope of license renewal.

In its response, by letter dated November 3, 2004, the applicant stated that LRA Section 2.3 lists the mechanical scoping and screening results. The only mechanical SR passive intended function of the neutron monitoring system is reactor coolant pressure boundary. The scoping and screening results for the electrical components of the neutron monitoring system are addressed in LRA Section 2.5. The applicant further stated that the "spaces approach" was utilized for scoping of electrical components, which does not exclude any electrical components from the scope of license renewal. The applicant included the subject components and its intended functions within the scope requiring an AMR.

Based on its review, the staff found the applicant's response to RAI 2.3.3.32-1 acceptable. The applicant included the subject components and their intended functions within the scope requiring an AMR. Therefore, the staff's concern described in RAI 2.3.3.32-1 is resolved.

2.3.3.32.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the neutron monitoring system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the neutron monitoring system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.33 Traversing In-Core Probe System

2.3.3.33.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.33, the applicant described the traversing in-core probe (TIP) system. The TIP system provides a signal proportional to the axial flux distribution at selected core locations where the local power range monitor detector assemblies are located. This signal allows reliable calibration of the power range monitor amplifiers. The TIP drive mechanism uses a detector that is attached to a flexible drive cable, which is driven from outside the primary containment by a gear box assembly. The flexible cable is contained by guide tubes that penetrate the reactor vessel and continue into the reactor core through a dry tube in a local power range monitor assembly. Provisions are made for automatic retraction of the detection and isolation of the primary containment penetration, when required.

The TIP system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- provides primary containment boundary isolation and integrity (active isolation function is not required)
- provides pressure boundary

In LRA Table 2.3.3.33, the applicant identified the following TIP system component types that are within the scope of license renewal and subject to an AMR: fittings, tubing, and valves.

2.3.3.33.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.33 and the UFSAR 5.2.3, 7.3, and 7.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.3.33.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the TIP system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the TIP system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.34 Cranes System

2.3.3.34.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.34, the applicant described the cranes system. The cranes system includes numerous plant load-handling devices that are used for maintenance of selected plant components.

The portions of the cranes system containing components subject to an AMR include the structural portions of the cranes in structures with SR components.

The failure of SR SSCs in the cranes system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides NSR components that ensure the satisfactory performance of SR components
- provides structural support

In LRA Table 2.3.3.34, the applicant identified the following cranes system component types that are within the scope of license renewal and subject to an AMR: bolting and fasteners, monorails, rail, rail clips, and structural girders.

2.3.3.34.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.34 and UFSAR Section 12.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.3.34, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued an RAI concerning the specific issue to determine whether the applicant had 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.

In RAI 2.3.3.34-1, the staff stated that in reviewing the cranes system described in LRA Section 2.3.3.34, the staff found that no drawings had been provided for this system. There is insufficient information for the staff to determine which cranes are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). In addition, mobile A-frames mentioned in LRA Section 2.1.2.2 are not mentioned in LRA Section 2.3.3.34 or in the UFSAR. Therefore, the staff requested that the applicant identify which cranes are within the scope of license renewal and subject to an AMR, and whether the mobile A-frames are within the scope of license renewal.

In its response, by letter dated October 19, 2004, the applicant stated that the buildings that contain NSR cranes and monorails that could prevent SR SSCs from performing their intended function(s) are the reactor building, primary containment, DG building, intake pumping station, and the reinforced concrete chimney. All cranes and monorails in these buildings are within the scope of license renewal. The applicant further stated that the mobile A-frames are cranes on wheels. These A-frames are within the scope of license renewal since they could be used in an SR building, they are also subject to an AMR.

Based on its review, the staff found the applicant's response to RAI 2.3.3.34-1 acceptable. It identifies the buildings containing the cranes that are within the scope of license renewal to meet the 10 CFR 54.4(a)(2) requirements, and it confirms that the mobile A-frames are within the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.34-1 is resolved.

2.3.3.34.3 Conclusion

The staff reviewed the LRA and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the cranes system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the cranes system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

In LRA Section 2.3.4, the applicant identified the structures and components of the steam and power conversion systems that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the steam and power conversion systems in the following sections of the LRA:

- 2.3.4.1 main steam system
- 2.3.4.2 condensate and demineralized water system
- 2.3.4.3 feedwater system
- 2.3.4.4 heater drains and vents system
- 2.3.4.5 turbine drains and miscellaneous piping system
- 2.3.4.6 condenser circulating water system
- 2.3.4.7 gland seal water system

The corresponding sections of this SER (2.3.4.1 – 2.3.4.7) present the staff's review findings with respect to the steam and power conversion systems for BFN.

2.3.4.1 Main Steam System

2.3.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.1, the applicant described the MS system. Each unit has its own MS system that consists of four MS lines that transfer steam from the reactor vessel to the various steam loads in the turbine building during normal plant operation. Two MSIVs are provided in each steam line to isolate the RCPB and the primary containment. A flow restrictor allows for the measurement of steam flow and also limits the steam flow rate in the event of a downstream steam line break. MSRVs are provided for overpressure protection and for depressurization following small-break LOCAs. Main steam components downstream of the MSIVs are credited in analyses for MSIV alternate leakage treatment.

The MS system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the MS system could prevent the satisfactory accomplishment of an SR function. In addition, the MS system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides for opening of safety relief valves (SRVs) during high reactor pressure to provide reactor pressure vessel relief
- provides MS line flow restrictors to passively limit the mass flow rate of the coolant being ejected following a steam-line break until MSIV closure occurs
- provides RCPB
- provides primary and secondary containment boundaries
- provides steam for the HPCI turbine

- establishes an MSIV leakage pathway to the condenser
- provides steam for the RCIC turbine
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.1, the applicant identified the following MS system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, piping, RCPB piping, restricting orifice, RCPB restricting orifice, strainers, tubing, valves, and RCPB valves.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 and UFSAR Sections 3.7, 4.1, 4.4, 4.5, 4.6, 4.11, 5.2.3, 5.3, 6.4.2, 7.2, 7.3, 7.4, 7.10, 7.11, 7.12, 7.18, 11.2, and 11.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.4.1, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI F 2.3.4.1-1, the staff stated that 0roviding a leakage pathway from the MSIVs to the main condenser is one of the intended functions of the main steam system. Regarding Unit 1, LRA Appendix F states that the segment of the main steam piping from the outermost isolation valve up to the turbine stop valve, the bypass/drain piping to the main condenser and the main condenser itself is being evaluated and modified as required to ensure that structural integrity during and after a safe shutdown earthquake (SSE) is maintained. The staff identified that portions of the main steam system (from the turbine building on) are not shown on license renewal drawing 1-47E801-1-LR as being subject to an AMR. However, similar segments of piping are shown as being subject to an AMR on license renewal drawings 2-47E801-1-LR and 3-47E801-1-LR. It is not clear to the staff, on the basis of a review of the drawings and the information provided in LRA Sections 2.1 and F.1 of Appendix F, why the sections of piping on license renewal drawing 1-47E801-1-LR are not subject to an AMR. Therefore, the staff requested that the applicant justify the exclusion of the piping sections in question from being within the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 25, 2004, the applicant stated that license renewal drawings depict components subject to an AMR based on the units' CLB. As documented in Appendix F.1 of the LRA, the Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing main steam piping and the main condenser because currently this modification is not physically implemented for Unit 1 to match Units 2 and 3 in their configuration.

The LRA was structured to reflect the configuration and CLB of all three units. Scoping and screening was done based on the CLB and configuration of all three units. The differences between the units that are relevant to the application and will be resolved prior to Unit 1 restart are listed in LRA Appendix F.

In addition, by letter dated January 31, 2005, the applicant provided additional/supplementary information, stating that as each activity identified in Appendix F is completed, the corresponding bold-bordered text in the LRA will apply to Unit 1. The applicant stated in its response that the only change to the application will be to remove the bolded border. No changes are required for scoping and screening, or AMR results, or TLAAs. However, in some cases, boundary drawings would change to reflect the bold-bordered text. The applicant committed to perform a secondary application review after the modification is implemented in the plant for Unit 1, and license renewal drawing 1-47E801-1-LR will be revised and submitted during the annual update. This will assure that the design changes that implement this modification do not modify or change the basis of how these components were initially scoped and screened.

Based on its review, the staff found the applicant's response to RAI F 2.3.4.1-1 acceptable. The Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing the main steam piping and main condenser and, therefore, this portion of piping is not subject to an AMR at this time. Upon completion of the modifications discussed in LRA Appendix F and the January 31, 2005, letter, the CLB for Unit 1 will be the same as Units 2 and 3. The review of LRA Appendix F regarding Unit 1 restart will be addressed in SER Section 2.6.1.1. Therefore, the staff's concern described in RAI F 2.3.4.1-1 is resolved.

In RAI F 2.3.4.1-2, the staff stated that license renewal drawings 2-47E801-2, 2-47E807-2, 3-47E801-2, and 3-47E807-2 highlight certain main steam system components for Units 2 and 3 associated with the reactor feed pump turbine drivers, the steam air ejector subsystem, and the steam seal regulator subsystem as being within the scope of license renewal and subject to an AMR. The corresponding components for Unit 1 should likewise be subject to an AMR. However, the drawings that show these components, such as license renewal drawings 1-47E801-2 (shown as a continuation line on drawing 1-47E801-1) and 2-47E807-2 and 3-47E807-2 (the corresponding drawings for Unit 1) are not provided. As a result, the staff was unable to determine if all of the aforementioned Unit 1 components, that are within the scope of license renewal and subject to an AMR for Units 2 and 3 were identified. Therefore, the staff requested that the applicant provide license renewal drawing 1-47E801-2 and the Unit 1 drawing that corresponds to drawings 2-47E807-2 and 3-47E807-2.

In its response, by letter dated October 25, 2004, the applicant stated that the license renewal drawings depict components subject to an AMR based on the units' CLB. As documented in LRA Appendix F.1, the Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing the main steam piping and main condenser. Appendix F.1 identifies the activities required to be completed in order to make the subject licensing basis applicable to Unit 1. Since activities required by LRA Appendix F.1 are not complete, the piping/components of the subject system are not subject to an AMR at this time.

The applicant further stated that at this time the modification to implement this change into the plant for Unit 1 has not been implemented. Therefore, the piping for Unit 1 does not perform the alternate leakage pathway function. The applicant further stated that once the modification has been implemented in the plant, Unit 1 license renewal drawings addressed in the RAI will be added to the application and submitted during the annual update with the same components on Unit 1 requiring an AMR as those shown on the Unit 2 and Unit 3 license renewal drawings.

Based on its review, the staff found the applicant's response to RAI 2.3.4.1-2 acceptable. It clarifies that the Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing main steam piping and the main condenser since the activities (identified in LRA Appendix F.1) required to make the Unit 1 CLB for MSIV leakage the same as that for Units 2 and 3 is not subject to an AMR at this time. The applicant also clarifies that once the modification is implemented, Unit 1 license renewal drawings will be submitted with the same components on Unit 1 that require an AMR as those shown on the Unit 2 and Unit 3 license renewal drawings. The review of LRA Appendix F regarding Unit 1 restart will be addressed in SER Section 2.6.1.1. Therefore, the staff's concern described in RAI 2.3.4.1-2 is resolved.

In order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments which support secondary containment, the applicant expanded the system boundaries for the main steam system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to its letter dated May 31, 2005, the applicant stated that additional piping, fittings, and valves had been added to scope. However, the component types do not differ from those listed in LRA Table 2.3.4.1; therefore, no changes to the main steam system portion of the LRA are required.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components

2.3.4.1.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawing, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the MS system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the MS system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Condensate and Demineralized Water System

2.3.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.2, the applicant described the condensate and demineralized water system. The main system is the condensate system which provides treated water at required flow rates for the FW system during normal plant operation. The system is unique to each unit and the individual systems do not share components with one another. The turbine-generator condenser provides a heat sink for the closed-loop steam cycle and removes non-condensable gases. In addition, impurities are removed by a full-flow demineralizer system. The system also cools the steam jet air ejector intercondenser, the off-gas condenser, and the steam packing exhauster condenser. The condenser is credited in analyses for MSIV alternate leakage treatment.

Subsystems of the condensate system are the condensate storage and transfer system, for radioactive high purity water, and the demineralized water system, for non-radioactive high purity water. The tanks also provide a surge volume for flow testing of HPCI, RCIC, and CS systems. The condensate water storage tanks and the demineralized water storage tank provide high purity water for miscellaneous makeup uses throughout the plant, which includes the reactor building.

The condensate and demineralized water system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the condensate and demineralized water system could prevent the satisfactory accomplishment of an SR function. In addition, the condensate and demineralized water system performs functions that support fire protection, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a normally open water supply to the RHR system piping flow path, which continues to the HPCI system piping that is located up-stream of the HPCI system pump
- provides primary and secondary containment boundaries
- provides a water supply for both HPCI and RCIC systems during an SBO
- retains fission products by plateout on a surface
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.2, the applicant identified the following condensate and demineralized water system component types that are within the scope of license renewal and subject to an AMR: bolting, condenser, expansion joint, fittings, piping, pumps, restricting orifice, tanks, tubing, and valves.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and UFSAR Sections 10.13, 11.8, 11.9, F.6.10, and F.6.18 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the condensate and demineralized water system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to the May 31, 2005 letter, the applicant stated that additional piping, fittings, valves, and the demineralized water tank have been added to scope. However, the component types do not differ from those listed in LRA Table 2.3.4.2; therefore, no changes to the condensate and demineralized water system portion of the LRA are required. The staff reviewed applicant's submittals and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.4.2.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the condensate and demineralized water system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the condensate and demineralized water system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Feedwater System

2.3.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.3, the applicant described the FW system. The FW system provides demineralized water at an elevated temperature to the reactor vessel during normal plant operations. FW is fed to the reactor vessel through six feedwater inlet nozzles. Suction for the system is drawn from the condensate system and FW is delivered to the reactor vessel at a controlled rate in order to maintain a stable reactor vessel water level. The system provides a flow path to the reactor vessel for the HPCI, RCIC, and RWCU systems.

The FW system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the FW system could prevent the satisfactory accomplishment of an SR function. In addition, the FW system performs functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides RCPB
- provides primary and secondary containment boundaries
- provides a path for HPCI system flow to the reactor pressure vessel through the feedwater spargers
- provides an injection path for the RCIC system
- provides a pressure boundary of the FW system components connected to the control air system that must maintain a pressure boundary in support of supplying containment atmosphere dilution to the MSRVs
- restricts flow
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.3, the applicant identified the following FW component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, RCPB fittings, piping, RCPB piping, RCPB restricting orifice, tubing, valves, and RCPB valves.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3 and UFSAR Sections 3.7, 4.2, 4.7.5, 4.9, 4.11, 5.2.3, 5.3, 6.4.1, 7.2, 7.3, 7.4, 7.8, 7.10, 10.17, and 11.8 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support secondary containment, the applicant expanded the system boundaries for the feedwater system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components outside secondary containment required to maintain the structural integrity of secondary containment that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2) for secondary containment qualification. In the enclosure to its letter dated May 31, 2005, the applicant stated that additional piping, valves, and heaters were added to scope. The component type, “heaters,” was added to LRA Table 2.3.4.3.

The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components.

2.3.4.3.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the FW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the FW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Heater Drains and Vents System

2.3.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.4, the applicant described the heater drains and vents system. The heater drains and vents system controls and contains the drains and vent paths from the various heaters associated with the main turbine cycle.

The heater drains and vents system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- establishes an MSIV leakage pathway to the condenser
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.4, the applicant identified the following heater drains and vents system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, traps, valves.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and UFSAR Section 11.8 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.4.4, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.4.4-1, the staff stated that pressure reducing valves PCV-1-151, -153, -166, and -167 are highlighted on license renewal drawing 2-47E801-2-LR as being within the scope of license renewal and subject to an AMR. However, the piping downstream of these pressure reducing valves is not within the scope of license renewal. Likewise, the similar arrangement for Unit 3 is shown on license renewal drawing 3-47E801-2-LR. Pressure reducing valves typically do not provide isolation capability if the downstream piping fails. Failure of the downsteam piping could effect the intended function of the heater drains and vents system that is required to establish MSIV leakage pathway to the condenser per LRA Section 2.3.4.4. Therefore, the staff requested that the applicant provide a basis for excluding the piping downstream of valves PCV-1-151, -153, -166, and -167 from the scope of license renewal and from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that a calculation issued in support of the MSIV leakage path listed these valves as a boundary. These pressure reducing valves close on loss of power, loss of air, and low steam line pressure. The applicant stated that TVA will review the qualification of the MSIV leakage path to identify the piping, supports and other components past the isolation valve required to maintain the structural integrity of the MSIV leakage pathway.

In a supplemental response dated May 31, 2005, the applicant provided the results of its review of the seismic qualification of the MSIV leakage path. As a result of the review, the following mechanical systems had systems boundary changes:

- main steam system
- auxiliary boiler system

However, the component types do not differ from those listed in the corresponding LRA tables; therefore, no changes to these systems' portion of the LRA are required.

The following mechanical systems had systems boundary changes; however, new component types were added that affected the scoping/screening results in the LRA.

- heaters drains and vents system
- off-gas system

The effect of these changes is evaluated and discussed in the corresponding sections of the SER. The remainder of the mechanical systems were not affected by this review.

Based on its review, the staff found the expanded scope of components to be acceptable, because the applicant had adequately included NSR components with the configurations that meet the scoping criterion of 10 CFR 54.4(a)(2) for the cases where NSR piping or components are directly connected to SR piping or components. Therefore, the staff's concern described in RAI 2.3.4.4-1 is resolved.

In RAI 2.3.4.4-2, the staff stated that check valves 742 and 744 are highlighted on license renewal drawing 2-47E801-2-LR as being within the scope of license renewal and subject to an AMR. However, the piping downstream of these check valves is not within the scope of license renewal. Likewise, the similar arrangement for Unit 3 is shown on license renewal drawing 3-47E801-2-R. Failure of the downstream piping would affect the intended function of the heater drains and vent system that is required to establish an MSIV leakage pathway to the condenser per LRA Section 2.3.4.4 and, therefore, should be within scope of license renewal as per 10 CFR 54.4(a)(2). Furthermore, the check valve orientation as shown on these drawings will not prevent flow to the downstream piping in the event of a failure. Therefore, the staff requested that the applicant provide a basis for excluding the piping downstream of check valves 742 and 744 from being subject to an AMR.

In its response, by letter dated October 19, 2004, the applicant stated that a calculation issued in support of the MSIV leakage path has these valves listed as a boundary. The applicant committed to review the qualification of the MSIV leakage path and identify the piping, supports and other components past the isolation valve required to maintain the structural integrity of the MSIV leakage pathway.

In a supplemental response dated May 31, 2005, the applicant stated that check valves 742 and 744 on boundary drawings 2-47E801-2-LR and 3-47E801-2-LR are spring-loaded and close on low pressure upon MSIV closure to prevent backflow through these valves.

Based on its review, the staff found the applicant’s response to RAI 2.3.4.4-2 acceptable, because it adequately addressed the intended function of check valves 742 and 744. Failure of the downstream piping during low-pressure events will not impede the intended function of these check valves. Therefore, the staff's concern described in RAI 2.3.4.4-2 is resolved.

In order to resolve the 10 CFR 54.4(a)(2) issues discussed in RAI 2.1-2A(1) and (2) of SER Section 2.1 related to NSR piping segments that support the MSIV leakage path, the applicant expanded the system boundaries for the heaters drains and vents system. By letter dated May 31, 2005, the applicant submitted the results of its review of piping, supports, and other components required to maintain the structural integrity of the MSIV leakage path that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). In the enclosure to the May 31, 2005 letter, the applicant stated that additional piping had been added to scope. However, the component type does not differ from those listed in LRA Table 2.3.4.4; therefore, no changes to the heater drains and vents system portion of the LRA are required. The staff reviewed the NSR piping segments and found the expanded scope of components to be acceptable because the applicant had adequately included NSR components with the configuration that meets the scoping criterion of 10 CFR 54.4(a)(2) for the case where NSR piping or components are directly connected to SR piping segments.

2.3.4.4.3 Conclusion

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

2.3.4.5 Turbine Drains and Miscellaneous Piping System

2.3.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.5, the applicant described the turbine drains and miscellaneous piping system. The turbine drains and miscellaneous piping system directs controlled leakage from various MS system components into the condenser.

The turbine drains and miscellaneous piping system contains SR components that are relied upon to remain functional during, and following, DBEs.

The intended functions within the scope of license renewal include the following:

- establishes an MSIV leakage pathway to the condenser
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.5, the applicant identified the following turbine drains and miscellaneous piping system component types that are within the scope of license renewal and subject to an AMR: bolting and valves.

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.4.5, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated October 8, 2004, the staff issued an RAI concerning the specific issues to determine whether the applicant had 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 response.

In RAI F 2.3.4.5-1, the staff stated that LRA Section 2.3.4.5 states that the intended function of the turbine drains and miscellaneous piping system is to establish MSIV leakage pathway to the condenser. The entire LRA section is enclosed in a bold text box. LRA Appendix F, Section F.1, "Main Steam Isolation Valve Alternate Leakage Treatment," states that the Unit 1 main steam piping from the outermost isolation valve up to the turbine stop valve, the bypass/drain piping to the main condenser, and the main condenser is being evaluated and modified as required to ensure that the structural integrity is retained during, and following, an SSE. However, it is not clear where the alternate leakage treatment flow path to the condenser exists on license renewal drawings 2-47E807-2-LR and 3-47E807-2-LR. Therefore, the staff requested that the applicant identify which portions of these drawings show components that are part of the leakage pathway to the condenser.

In its response, by letter dated October 25, 2004, the applicant stated that the alternate leakage path ensures that process lines containing steam have a boundary that contains an isolation point to form a preferred leakage path to the condenser. The boundary was established at the first closed valve or fails-closed valve on the red lines continuing from LR drawings 2-47E801-2-LR, 2-47E807-1-LR, 3-47E801-2-LR, and 3-47E807-1-LR.

Based on its review, the staff found the applicant's response to RAI F 2.3.4.5-1 acceptable. It adequately identifies the portions of the license renewal drawings showing components that are part of the leakage pathway to the condenser. Therefore, the staff's concern described in RAI F 2.3.4.5-1 is resolved.

2.3.4.5.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the turbine drains and miscellaneous piping system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the turbine drains and miscellaneous piping system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.6 Condenser Circulating Water System

2.3.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.6, the applicant described the condenser circulating water system. Each unit contains a condenser circulating water system that does not share any components with the other units' systems. Each unit has three circulation water pumps that take water from a common intake channel in Wheeler Reservoir. After passing through the condensers, the heated water is cooled by the cooling towers or discharged directly back to Wheeler Reservoir. Provisions, including a loop in the discharge conduit with a vacuum breaker, are made for the prevention of the backflow of heated water into the intake channel, which serves as the ultimate heat sink, if normal offsite power is lost. One condenser circulating water pump has more than enough capacity to dissipate the shutdown heat for all three of the units.

The condenser circulating water system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the condenser circulating water system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a manual vacuum breaking capability to prevent backflow from cooling tower warm channel into the forebay upon trip of the condenser circulating water pumps
- provides mechanical closure
- provides structural support

In LRA Table 2.3.4.6, the applicant identified the following condenser circulating water system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, strainers, tubing, and valves.

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 and UFSAR Sections 2.4.2.2.2, 11.6, 12.2.7, and F.6.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed the components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.3.4.6, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated August 31, 2004, the staff issued RAIs concerning the specific issues to determine whether the applicant had 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.

In RAI 2.3.4.6-1, the staff stated that LRA Section 2.3.4.6 indicates that a vacuum-breaker valve, located in a piping loop in the discharge conduit of the condenser circulating water (CCW) system, is provided to prevent the backflow of heated cooling tower effluent from the warm water channel into the intake channel which serves as an ultimate heat sink. Backflow can occur upon loss of offsite power with attendant trip of the CCW pumps if the level in the warm water channel exceeds that in the intake channel. As indicated in the LRA, the components comprising this vacuum breaking subsystem require an AMR.

On the license renewal boundary drawings for Unit 1, all components comprising this subsystem are shown within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). However, the drawings for Units 2 and 3 show only the vacuum-breaker valves themselves in scope under 10 CFR 54.4(a)(1), while the associated loop piping and fittings are shown either within scope under 10 CFR 54.4(a)(2) or else outside of scope. Therefore, the staff requested that the applicant justify why the components comprising this subsystem had been classified differently for Units 2 and 3 than for Unit 1.

In its response, by letter dated October 19, 2004, the applicant stated that DCN 51360A was issued to reclassify the loop piping and fittings of the above-mentioned subsystem from SR to NSR, for all three units. However, at the time of the LRA submittal, implementation of this DCN had been completed for Units 2 and 3 but not for Unit 1. This resulted in the differences in classification noted above. Additionally, the applicant stated that the above referenced loop components for Units 2 and 3, which are classified as outside the scope of license renewal, should have been classified as within scope under 10 CFR 54.4(a)(2). This error will be corrected on the drawings for Units 2 and 3. It was further noted that, since DCN 51360A has now been completed for Unit 1, the drawings for this unit have been revised to be consistent with those for Units 2 and 3 and will be resubmitted as part of the annual update.

Based on its review, the staff found the applicant's response to RAI 2.3.4.6-1 acceptable. The differences in component classification noted above have been satisfactorily explained and the corresponding drawings have been appropriately corrected. Therefore, the staff's concern described in RAI 2.3.4.6-1 is resolved.

In RAI 2.3.4.6-2, the staff stated that components of the CCW system that are subject to an AMR are shown in LRA Table 2.3.4.6. These components described in RAI 2.3.4.6-1 comprise the vacuum breaking subsystem. For the components listed, the table shows that structural support is the sole intended function for each (except bolting which has the additional intended function of mechanical closure). However, it would appear that the pressure boundary of the components comprising this subsystem must remain intact to effect a break in vacuum. Accordingly, each of these components should have the additional intended function of pressure boundary. Therefore, the staff requested that the applicant justify why the intended function pressure boundary is not included in LRA Table 2.3.4.6 for each of the components listed.

In its response, by letter dated October 19, 2004, the applicant stated that maintaining an intact pressure boundary for the components listed in LRA Table 2.3.4.6 is not required, because the vacuum-breaking valve in this subsystem could perform its intended function, even if leakage were to occur in the associated piping or fittings.

Based on its review, the staff found the applicant's response to RAI 2.3.4.6-2 acceptable. It adequately explains why the intended function of pressure boundary is not required for the components in question. Therefore, the staff's concern described in RAI 2.3.4.6-2 is resolved.

2.3.4.6.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the condenser circulating water system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the condenser circulating water system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.7 Gland Seal Water System

2.3.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.7, the applicant described the gland seal water system. The gland seal water system provides pressurized sealing water to the condenser and condensate system components that are under a vacuum in order to prevent air leakage into the condenser. Each individual system has an elevated gland seal tank that is located in the reactor building and also contains the associated piping that maintains a static pressure on seals (e.g., packing) of components of the main condenser and condensate systems that are under a vacuum during normal plant operations.

The gland seal water system contains SR components that are relied upon to remain functional during, and following, DBEs. The failure of NSR SSCs in the gland seal water system could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a secondary containment boundary
- provides mechanical closure
- provides pressure boundary
- provides structural support

In LRA Table 2.3.4.7, the applicant identified the following gland seal water system component types that are within the scope of license renewal and subject to an AMR: bolting, fittings, piping, tanks, tubing, and valves.

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in 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 had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.3.4.7.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the gland seal water system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the gland seal water system components 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:

- boiling water reactor containment structures
- Class I Group 2 structures
- Class I Group 3 structures
- Class I Group 6 structures
- Class I Group 8 structures
- Class I Group 9 structures
- non-Class I structures
- structures and component supports commodities

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived structural SSCs 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 there were no omissions of structures and components that meet the scoping criteria and are subject to an AMR.

Staff Evaluation Methodology. The staff's evaluation of the information provided in the LRA was performed in the same manner for all structures. The objective of the review was to determine if the components and supporting structures for a specific structure that appeared to meet the scoping criteria specified in the Rule had been identified by the applicant 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 were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

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

Screening. Once the staff completed its review of the scoping results, the staff evaluated the applicant's screening results. For those structures and components 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 that did not meet either of these criteria, the staff sought to confirm that these structures and components were subject to an AMR as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.4.1 Boiling Water Reactor Containment Structures

2.4.1.1 Primary Containment Structure

2.4.1.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1.1, the applicant described the primary containment structure. The primary containment structure is a General Electric Mark I containment design. Each unit has a primary containment structure that is completely enclosed within the unit's reactor building. The main function of the primary containment structure is to limit the release of fission products to the environment in the event of a design-basis LOCA.

The primary containment consists of a drywell, pressure suppression chamber, and a connecting vent system. The drywell is a steel pressure vessel enclosed in reinforced concrete. The drywell contains the reactor vessel, reactor recirculation system, and portions of other systems that form the reactor coolant pressure boundary. Also included within the drywell are structural steel framing, electrical and mechanical equipment and system supports, a concrete shield wall around the reactor vessel, a removable steel head, a personnel airlock with two mechanically interlocked doors, two equipment hatches, and miscellaneous electrical and mechanical penetrations. The pressure suppression chamber is a steel, toroidal-shaped pressure vessel. The pressure suppression chamber is commonly referred to as the "torus." The torus includes internal steel framing, vent header, supports, access hatches, and penetrations. The torus is mounted on support structures that transmit loads to the concrete foundation of the reactor building. The drywell is connected to the pressure suppression chamber with eight equally spaced vent lines. These vent lines are connected to a header, which is contained within the air space of the pressure suppression chamber. The pressure suppression chamber contains a large pool of water that condenses the steam from a failure of the reactor coolant pressure boundary piping in the drywell. The pool also condenses steam from the main steam relief valve discharge, high pressure coolant injection, and reactor core isolation cooling turbine discharge.

The primary containment structure contains SR SSCs that are relied upon to remain functional during, and following, DBEs to ensure the integrity of the reactor coolant pressure boundary, shut down the reactor and maintain it in a safe shutdown condition, and prevent or mitigate the consequences of accidents that could result in potential offsite exposure. The failure of NSR SSCs in the primary containment structure could prevent the satisfactory accomplishment of an SR function. In addition, the primary containment structure performs functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for components relied upon to demonstrate compliance with fire protection, EQ, and ATWS regulated events
- provides structural support and shelter/protection for SR components, NSR components, and components relied upon to demonstrate compliance with the SBO regulated event

- limits and controls the release of fission products to the secondary containment during DBAs
- provides sufficient air and water volumes to absorb the energy released to the containment during DBAs
- provides a source of water to the emergency core cooling systems
- provides protection to personnel and components from radiation
- provides a pressure boundary
- shelters and protects a component from the effects of weather or localized environmental conditions
- reduces a radiation dose
- provides structural and functional support for structures and components that are within the scope of license renewal

In LRA Table 2.4.1.1, the applicant identified the following primary containment structure component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- compressible joints and seals
- controlled leakage doors
- hatches/plugs
- high density shielding concrete
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs
- steel containment elements
- structural bellows
- structural steel beams, columns, plates, and trusses

2.4.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1.1 and UFSAR Sections 5.2, 12.2.2 and C.5 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.1.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.4-2, dated December 20, 2004, the staff stated that in reviewing LRA Section 2.4.1.1, it noted that this section of the LRA should address not only the primary containment (drywell, pressure suppression chamber, and the vent system connecting the two structures), but also all the structures inside the primary containment, all attachments to the containment, and the containment supports. The staff also noted that LRA Table 2.4.1.1 identified the primary containment component types requiring AMR and the associated component intended function(s). Since LRA Table 2.4.1.1 combined many components under a single component type, the staff requested that the applicant identify which component type had been intended to cover the specific components listed in (a) through (k) below, or to identify the location in the LRA where these specific components had been addressed. If these specific components had not been considered to be within the scope of license renewal, the applicant was requested to provide the technical bases for their exclusion.

a. reactor vessel to biological shield stabilizers

b. biological shield to containment stabilizer

c. reactor pressure vessel (RPV) male stabilizer attached to outside of drywell shell

d. RPV female stabilizer and anchor rods (also referred to as gib) embedded in reactor building concrete wall

e. biological shield wall and anchor bolts

f. reactor vessel support skirt and anchor bolts

g. reactor vessel support ring girder and anchor bolts

h. reactor vessel support pedestal

i. drywell internal steel shear ring

j. drywell steel support skirt and anchor bolts

k. drywell head closure bolts and double gasket, tongue-and-groove seal arrangement

By letter dated January 24, 2005, the applicant provided the following response:

> The Primary Containment Structure scoping and screening results are presented in LRA Section 2.4.1.1, the Reactor Vessel scoping and screening results are presented in LRA Section 2.3.1.1, and the Structures and Component Supports Commodity Group scoping and screening results are presented in LRA Section 2.4.8.1. The following list of components roll-up to the listed component groups:
>
> (a) Reactor Vessel to Biological Shield Stabilizers:
>
> - Table 2.4.8.1, ASME Equivalent Supports and Components;
> - Table 3.5.2.26, ASME Equivalent Supports and Components;
> - Table 2.3.1.1, Stabilizer Bracket;
> - Table 3.1.2.1, Stabilizer Bracket; and
> - LRA Section 3.1.2.2.16.1 BWRVIP-74-A Table 4-1 Items.
> - NOTE: This biological shield wall is internal to the drywell.

(b) Biological Shield to Containment Stabilizer:

- Table 2.4.1.1, Steel Containment Elements; and
- Table 3.5.2.1, Steel Containment Element.
- NOTE: This biological shield wall is internal to the drywell.

(c) RPV Male Stabilizer Bracket Attached to Outside of Drywell Shell:

- There is no RPV male stabilizer bracket attached to the outside of the Drywell shell at BFN. There is a stabilizer from the internal biological shield wall to the inside containment shell that is a subset of biological shield to containment stabilizer noted in (b) above.

(d) RPV Female Stabilizer and Anchor Rods (also referred to as Gib) embedded in Reactor Building concrete wall:

- There is no RPV female stabilizer and anchor rods (also referred to as Gib) embedded in Reactor Building concrete wall at BFN. There is a female stabilizer and anchor rods assembly embedded in Reactor Building concrete wall (also a biological shield wall external to Drywell) and is a subset of biological shield to containment stabilizer noted in (b) above.

(e) Biological Shield Wall and Anchor Bolts:

- Table 2.4.1.1, High Density Shielding Concrete;
- Table 3.5.2.1, High Density Shielding Concrete (Un-reinforced shielding concrete is encased between steel plates and is inaccessible. The steel plates are included with structural steel internal to drywell);
- Table 2.4.1.1, Structural Steel Beams, Columns, Plates, Trusses; and
- Table 3.5.2.1, Structural Steel Beams, Columns, Plates, Trusses.
- NOTE: This biological shield wall is internal to the drywell.

(f) Reactor Vessel Support Skirt and Anchor Bolts:

- Table 2.3.1.1, Support Skirt and Attachment Welds;
- Table 3.1.2.1, Reactor Vessel Support Skirt and Attachment Welds;
- LRA Section 3.1.2.2.16.1 BWRVIP-74-A Table 4-1 Items;
- Table 2.4.8.1, ASME Equivalent Supports and Components; and
- Table 3.5.2.26, ASME Equivalent Supports and Components (includes anchor bolts).

(g) Reactor Vessel Support Ring Girder and Anchor Bolts:

- Table 2.4.8.1, ASME Equivalent Supports and Components; and
- Table 3.5.2.26, ASME Equivalent Supports and Components (includes anchor bolts).

(h) Reactor Vessel Support Pedestal:

- Table 2.4.1.1, Reinforced Concrete Beams, Columns, Walls, and Slabs; and
- Table 3.5.2.1, Reinforced Concrete Beams, Columns, Walls, and Slabs.

(i) Drywell Internal Steel Shear Ring:

- BFN does not have a "Drywell Internal Steel Shear Ring"

(j) Drywell Steel Support Skirt and Anchor Bolts:

- Table 2.4.1.1, Steel Containment Elements; and
- Table 3.5.2.1, Steel Containment Elements (Drywell steel support skirt is part of the Class MC drywell support and the skirt and anchor bolts are encased in concrete; therefore, they are inaccessible.)

(k) The Drywell Head Closure Bolts and Double Gasket, Tongue and Groove Seal Arrangement:

- Table 2.4.1.1, Steel Containment Elements;
- Table 3.5.2.1, Steel Containment Elements (Includes drywell head closure bolts);
- Table 2.4.1.1, Compressible Joints & Seals; and
- Table 3.5.2.1, Compressible Joints & Seals.

Based on the response to RAI 2.4-2 by letter dated January 24, 2005, the staff found that the components identified in the RAI are covered under the scope of LRA Section 2.4.1, except item (f), which is covered under the scope of LRA Section 2.3. However, 10 CFR 54.4(a) and (b) require identification of all in-scope structures and components and their intended functions. The staff reviewer assumed that the drywell and suppression chamber supports (items (j) and (k)) are within the scope of license renewal; however, an absence of all structural components internal to drywells and suppression chambers (Items (a) to (e), and items (g) and (h)) from LRA Table 2.4.1.1 implies that they are not within the scope of license renewal. The applicant was requested to explicitly incorporate the components internal to drywells and suppression chambers within the scope of license renewal, through cross referencing, if necessary.

In a follow-up response to RAI 2.4-2, by letter dated May 24, 2005, the applicant stated that the methodology used to determine the components within the scope of license renewal is described in LRA Section 2.1.4.3.3, “Structural Component Scoping,” and reads as follows:

For structures determined to be within the scope of 10 CFR 54, detailed structural drawings were reviewed to identify structural components (such as structural steel, foundations, floors, walls, ceilings, penetrations or stairways). For in-scope structures, all structural components that are required to support the intended functions of the structure were identified as in-scope of 10 CFR 54. These structural components were generally evaluated as generic structural commodities, not as individual components.

LRA Section 2.4.1.1 addresses the primary containment structure and includes all component types, as noted in LRA Table 2.4.1.1. The component type “Reinforced Concrete Beams, Columns, Walls, and Slabs” includes the concrete of the reactor vessel support pedestal and other structural concrete located within the primary containment structure. The component type “High Density Shielding Concrete” includes the concrete of the biological shield wall. The component type “Structural Steel Beams, Columns, Plates, Trusses” includes the plates that form the cylindrical shell of the biological shield wall and other structural steel components such as the steel platforms located within the primary containment structure. The component type “Steel Containment Elements” includes the stabilizers between the biological shield wall and containment shell, RPV male stabilizer bracket and RPV female stabilizer and anchor bolts, drywell, drywell steel support skirt and anchor bolts, drywell head and closure bolts, torus and torus ring girder, embedded steel, and other components that comprise the primary containment boundary of the primary containment structure. The component type “Compressible Joints and Seals” includes the gasket material used in the drywell head seal, drywell and torus access hatch seals, and personnel access doors and penetration seals located in the primary containment structure. Components identified as supports that are located within the primary containment structure were addressed in Section 2.4.8.1, Structures and Component Supports Commodity Group. The component type “ASME Equivalent Supports and Components” includes the anchor bolts of the RPV support skirt, RPV ring girder and anchor bolts and other supports for ASME Code Class 1 and Class 2 piping within the primary containment structure.

Based on this detailed description of the commodity groups that are included within the scope of license renewal, the staff found that all structural as well as non-structural (e.g., seals and gaskets) components within the primary containment structures have been included within the scope of license renewal. Therefore, the staff found the applicant’s scoping of the components within the primary containment acceptable, and the staff’s concern described in RAI 2.4-2 is resolved.

In RAI 2.4-3, dated December 20, 2004, the staff explained its concern that leakage through the refueling seals located at the top of the drywell potentially exposes the carbon steel drywell shell inner and outer surfaces to loss of material due to corrosion. This is a particular concern for the embedded portion of the drywell shell. Corrosion detected on the outer shell surface in the sand pocket region in a number of Mark I steel containments has been attributed to leakage past the drywell-to-reactor building refueling seal, coupled with clogging of the sand pocket drains. Leakage into the drywell past the reactor vessel-to-drywell refueling seal creates the potential for corrosion of the inaccessible portion of the inner surface of the drywell shell embedded in the concrete floor.

From the information contained in the LRA, the staff stated that it was not clear (1) whether the refueling seals had been included within the scope of license renewal, and (2) if included, how aging management of the seals was addressed. Therefore, the staff requested the applicant to verify that the BFN plants' refueling seals were included in a component type that required an AMR, or a detailed explanation for their exclusion. The staff also requested the applicant to provide a detailed description of the plant-specific operating experience for the refueling seals in all three 3 units, including incidences of degradation, method of detection, root cause, corrective actions, and current inspection procedures.

In its response, by letter dated January 24, 2005, the applicant stated that BFN it had not included the refueling seals at the top of the drywell within the scope of license renewal, and explained its logic as follows:

> The performance of the drywell-to-reactor building refueling seal is not considered a safety-related function. The drywell to reactor building refueling seal and the reactor pressure vessel (RPV)-to-drywell refueling seal, in conjunction with the refueling bulkhead, provides a watertight barrier to permit flooding above the RPV flange while preventing water from entering the drywell. Providing a watertight barrier to permit flooding above the RPV flange in support of refueling operations is not a safety-related function.

Moreover, the applicant stated that the performance of the drywell-to-reactor building refueling seal is not considered a II over I issue by quoting 10 CFR 54.4(a)(2): "All non safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section," and provided the following explanation:

> A postulated failure of the drywell-to-reactor building refueling seal can result in water intrusion into the annulus space around the drywell. This leakage can occur only during refueling outages when the reactor cavity is flooded to allow movement of fuel between the reactor and the fuel pool. However, water intrusion does not cause failure of the drywell's intended function. Any water leakage resulting from a postulated failure of the drywell-to-reactor building refueling seal could not remain suspended in the annulus region for an indefinite period of time and would eventually be routed to the sand-pocket area drains or would evaporate due to the heat generated in the drywell during operation.

The staff disagreed with the applicant's rationale for not including the reactor building-to-drywell refueling seals within the scope.

In OI 2.4-3, the staff explained that Supplement 1 of IE IN 86-99 indicates that if leakage from the flooded reactor cavity is not monitored and managed, there is a potential for corrosion of the cylindrical portion of the drywell shell. As this corrosion would initiate in the non-inspectible areas of the drywell, it cannot be monitored by IWE inspections. Moreover, this degradation of the drywell shell can occur even if there is very little water found in the sand pocket area of the drywell. Thus, the reactor building-to-drywell refueling seal becomes a nonsafety item, that can affect the integrity of the drywell shell (which is a pressure boundary component) during the period of extended operation, and falls under the requirement of 10 CFR 54.4(a)(2). Furthermore, the staff offered an alternative by citing two BWR plants where the staff had accepted in the past an alternative to managing the aging of the seal. The alternative is to periodically perform ultrasonic testing (UT) of the cylindrical portion of the drywell shell with an acceptable sampling program, as part of the containment ISI program. After reviewing the response to RAI 3.5-4 (in the applicant's letter dated January 31, 2005) related to the operating experience of drywell shell corrosion at all three units of BFN, the staff came to the conclusion that the applicant should manage the aging (leakage) of refueling seals. The applicant was requested to include the refueling seals within the scope of license renewal.

In its response, by letter dated May 31, 2005, the applicant emphasized that BFN does not include the refueling seals at the top of the drywell in the scope of license renewal and provided the following technical basis for that conclusion:

> The drywell-to-reactor building refueling seal and the reactor pressure vessel (RPV)-to-drywell refueling seal, in conjunction with the refueling bulkhead, provide a watertight barrier to permit flooding above the RPV flange while preventing water from entering the drywell. Providing a watertight barrier to permit flooding above the RPV flange in support of refueling operations is not a safety-related function. 10 CFR 54.4(a) sets forth the criteria that determine whether plant systems, structures, and components are within the scope of license renewal. The refueling seals do not satisfy any of the requirements set forth in 10 CFR 54.4(a)(1). The refueling seals are not safety related and they are not relied upon to remain functional during design basis events to ensure 10 CFR 54.4(a)(1)(i) the integrity of the reactor coolant pressure boundary, 10 CFR 54.4(a)(1)(ii) the capability to shut down the reactor and maintain it in a safe shutdown condition, or 10 CFR 54.4(a)(1)(iii) the capability to prevent or mitigate potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11. Thus, the refueling seals are not brought into scope of license renewal by 10 CFR 54.4(a)(1).

Additionally, the applicant stated that the performance of the drywell-to-reactor building refueling seal and the RPV-to-drywell refueling seal, in conjunction with the refueling bulkhead is not considered a II over I issue. 10 CFR 54.4(a)(2) states, "All non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section." A postulated failure of the drywell-to-reactor building refueling seal can result in water intrusion into the annulus space around the drywell. This leakage can occur only during refueling outages when the reactor cavity is flooded to allow movement of fuel between the reactor and the fuel pool. However, water intrusion does not cause failure of the drywell's intended function. Any water leakage resulting from a postulated failure of the drywell-to-reactor building refueling seal could not remain suspended in the annulus region for an indefinite period of time and would eventually be routed to the sand pocket area drains or would evaporate due to the heat generated in the drywell during operation. The refueling seals are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for fire protection, EQ, PRS (N/A for BWRs), ATWS, or SBO. The applicant discussed in detail the differences between condition of the BFN units and that of Dresden 3, and emphasized that the BFN refueling seals are not within the scope of license renewal and do not require aging management review. The applicant also pointed out that Hatch Units 1 and 2 (NUREG-1803), Peach Bottom Units 2 and 3 (NUREG-1769) and Dresden Units 2 and 3 and Quad Cities 1 and 2 (NUREG-1796) did not identify refueling seals to be within the scope of license renewal. Thereafter, the applicant provided a detailed description of the BFN steel shell inspections in the sand pocket areas (these are discussed in the staff's evaluation of RAI 3.5-4), and concluded: "Based on Browns Ferry scoping results, Browns Ferry operating experience, and prior industry precedents, Browns Ferry refueling seals are not in the scope of license renewal, nor are additional drywell inspections warranted at Browns Ferry."

Follow-up OI RAI 2.4-3 - In a detailed response to the staff's follow-up item 3.5-4 related to the seal area near the drywell flange, by letter dated May 31, 2005, the applicant stated:

> This area is exposed to standing water and repeated wetting and drying during refueling operations. The area is not accessible for detailed visual examination from the outside surface. There are no documented UT thickness measurements of this area. No previous problems have been documented relative to degradation of this area. Standing water was observed in this area during the April, 1998 Unit 3 mid-cycle outage, during a walkdown performed immediately following drywell head removal and prior to floodup. Since the true surface condition can not be determined by visual examination or review of existing data, this area appears to warrant additional investigation to determine whether it should be included for augmented examination.

In its response, the applicant also provided a description of the limited number of UT measurements taken. The staff expressed its belief that 10 CFR 54.4(a)(2) applies to the uninspectable side of the drywell shell, as significant corrosion of the drywell shell would jeopardize capability of the primary containment to prevent or mitigate the consequences of accidents as per 10 CFR 54.4(a)(1)(iii). Based on the applicant's responses to RAI 2.4-3, and the follow-up RAI 3.5-4, the staff did not insist on having the drywell-to-reactor building seal within the scope of license renewal. However, the staff indicated that it needed assurance that the potential degradation of the uninspectable side of the drywell will be monitored and managed during the period of extended operation. This remained as OI 2.4-3.

In its letter dated November 16, 2005, the applicant explained that to provide the staff with the necessary assurance that the potential degradation of the uninspectable side of the drywell is being monitored and managed, the applicant will perform one-time confirmatory ultrasonic thickness measurements on a portion of the cylindrical section of the drywell in a region where the liner plate is 0.75 inches thick. These ultrasonic thickness measurements will be obtained at four locations, approximately 90° apart, in an area at least three feet by three feet with measurements taken at intersection points of approximately one-foot grids. This will provide a bounding condition since the nominal thickness of the wall in this region has the least margin. These ultrasonic thickness measurements will be obtained on Unit 2 and Unit 3 prior to the period of extended operation to provide added assurance that the integrity of the drywell shell is not being compromised by wastage before entering into the renewed licensing period.

For Unit 1, the applicant explained that it will perform one-time confirmatory ultrasonic thickness measurements on the vertical cylindrical area immediately below the drywell flange. This area is exposed to standing water and repeated wetting and drying during refueling operations. These ultrasonic thickness measurements will be obtained on the entire vertical portion of the liner accessible from inside drywell above elevation 637.0' (Az 0° - Az 360°) with measurements taken at intersection points of approximately one-foot grids. These ultrasonic thickness measurements will be obtained prior to Unit 1 restart. Similar inspections have been performed on Units 2 and 3 in this area as documented in BFN plant procedure 0-TI-376, Appendix 9.7. A discussion of the inspection for Units 2 and 3 is contained in the applicant's response to follow-up RAI 3.5-4, page E-13 in the letter from TVA to the NRC dated May 31, 2005.

The applicant, further asserted that data from the ultrasonic thickness measurements described above will be reviewed by its engineering division. If any areas of concern or non-conforming conditions are identified, a PER will be initiated in accordance with the site Corrective Action Program, SPP-3.1. A corrective action plan will be developed in accordance with SPP-3.1 and an extent of condition and applicability to the other BFN units would be considered in the disposition of the PER.

As part of its response, the applicant emphasized that the BFN configuration of the refueling cavity-to-drywell seal is different from that of a number of other Mark I containments. There is no gasket at the drain, and the applicant claimed that it is able to monitor the leakage from the refueling seal, if it occurs. However, the applicant could not satisfactorily explain the root cause of water in the sand pocket areas. Therefore, the applicant chose to monitor the cylindrical inaccessible areas of the three BFN units. For Units 2 and 3, the applicant will perform an augmented inspection of these areas one time prior to the periods of extended operation; and, for Unit 1, it will perform the inspection of these areas prior to Unit 1 restart. As part of these inspections, if the applicant discovers non-conforming conditions, it will take appropriate corrective actions. After careful review of the applicant's commitments, the staff considered the approach proposed by the applicant acceptable; therefore, OI 2.4-3 is closed.[1]

2.4.1.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the primary containment structure components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the primary containment structure components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Class 1 Group 2 Structures

In LRA Section 2.4.2, the applicant identified the structures and components of the Class 1 Group 2 structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the Class 1 Group 2 structures in the following sections of the LRA:

- 2.4.2.1 reactor buildings
- 2.4.2.2 equipment access lock

The corresponding subsections of the SER, 2.4.2.1 – 2.4.2.2, present the staff's review findings with respect to the Class 1 Group 2 structures for BFN.

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[1] The OI-2.3-3 was discussed in the ACRS 530th full committee meeting on March 9, 2006. Additional discussion on this OI is provided in SER supplement NUREG-xxxx.

2.4.2.1 Reactor Buildings

2.4.2.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.1, the applicant described the reactor buildings. Each unit has its own reactor building that completely encloses the reactors, the primary containment structures, and the auxiliary and emergency systems of the nuclear steam supply system (NSSS). A major substructure of the reactor building is the reinforced concrete biological shield that surrounds the drywell portion of the primary containment. The reactor buildings house features such as the spent fuel pool, steam dryer/moisture separator storage pool, reactor cavity, reactor auxiliary equipment, refueling equipment, reactor servicing equipment, and the control bay. The control bay houses the main control room that is required for plant operation and the operation of other important auxiliary systems. The reactor building consists of monolithic, reinforced concrete floors and walls from the foundation to the refueling floor. The refueling floor is common for all three units and is enclosed by the steel superstructure with metal siding and a built-up roof. Blowout or pressure relief panels are installed as part of the reactor building superstructure to relieve pressure during a DBA or DBE.

The reactor buildings contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the reactor buildings could prevent the satisfactory accomplishment of an SR function. In addition, the reactor buildings perform functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides controls for the potential release of fission products to the external environment
- provides a secondary containment function when the primary containment is required to be in service
- provides a primary containment function during reactor refueling and maintenance operations when the primary containment systems are open
- provides radiation shielding protection for personnel, equipment, and components
- provides structural support and shelter/protection for components relied upon to demonstrate compliance with the fire protection, EQ, and ATWS regulated events
- provides structural support and shelter/protection for SR components, NSR components, and components relied upon to demonstrate compliance with the SBO regulated event
- provides protection for the safe storage of new and spent fuel
- prevents criticality of new and spent fuel
- allows for expansion of a component
- provides a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provides flood protection barrier for internal and external flooding events

- provides protection against the effects of a high-energy or low-energy (moderate) line break
- provides a barrier for protection against internally or externally generated missiles
- provides a pressure boundary
- shelters and protects a component from the effects of weather or localized environmental conditions
- reduces a radiation dose
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.2.1, the applicant identified the following reactor buildings component types that are within the scope of license renewal and subject to an AMR:

- bolting and fasteners
- caulking and sealants
- compressible joints and seals
- controlled leakage doors
- expansion joints
- fire barriers
- hatches and plugs
- masonry block
- metal roofing
- metal siding
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs
- roof membrane
- spent fuel pool liners
- spent fuel storage racks (includes new fuel storage racks)
- structural steel, beams, plates, and trusses

2.4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.1 and UFSAR Sections 5.3 and 12.2.2 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.2.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

The staff noted that LRA drawing 0-10E201-01-LR, "License Renewal Screening for Information Only Location of Structures," identifies structures that are not within scope of license renewal. These structures include east access facility, isolation valve pits, radwaste building, south access retaining walls, water and oil storage building, part of gate structure No.2 adjacent to diesel high-pressure fire pump house, raw water treatment facility, structural elements within the transformer yard, and other miscellaneous buildings. It was not clear to the staff that all of the above listed structures serve no intended function as defined in 10 CFR 54.4(a)(1).

In RAI 2.4-1, dated December 20, 2004, the staff asked the applicant to provide additional descriptive information for the above-listed structures, define their function, and describe the technical bases for exclusion from the license renewal scope. The applicant was also requested to verify that none of these structures serve a seismic II/I intended function as defined in 10 CFR 54.4(a)(2).

In its response, by letter dated January 24, 2005, the applicant stated the following:

> These five (5) structures; East Access Facility, Radwaste Building, Water and Oil Storage Building, part of Gate Structure No.2 adjacent to Diesel High Pressure Fire Pump House, and Raw Water Treatment Facility are groups of Class II (NSR) structures and major civil features that do not satisfy the requirements of 10 CFR 54.4(a). These five structures provide structural support and anchorage for NSR equipment and equipment that is not required to support regulated events (ATWS, fire protection, EQ, and SBO). None of the five structures and major components in these structural groups serves a seismic II/I intended function. This was the technical basis for exclusion from the license renewal scope. A more detailed description and functions is provided below for each of the five structures. A more detailed description of the South Access Retaining Walls, the Isolation Valve Pits, and the structural elements within the Transformer Yard and other miscellaneous buildings is also provided below.
>
> East Access Facility
>
> This facility is a set of two temporary Class II (non-safetyrelated) buildings built originally to support the recovery of BFN unit 3. One building provides office space and shop area for site maintenance personnel. The other building provides access for site personnel, plant material and plant equipment into the powerhouse (through the unit 3 Turbine Building) and a radiation control point for same entering or exiting the unit 3 Turbine Building.
>
> Isolation Valve Pits
>
> These Class II (non-safety-related) structures are manholes that provide structural support and shelter protection for the hardened wetwell vent piping and components. Upon further review, it has been noted that the hardened wetwell vent is in scope for license renewal per section 2.3.2.1, Containment System (064). The hardened wetwell vent was a commitment to GL 89-16. These isolation valve pits are Class II (NSR) structures and since they provide an intended function for an in-scope mechanical

system (54.4(a)(2)), they should be included within the scope of the LRA. Refer to Attachment 1 for the affected sections of the application with the required scoping, screening and aging management review results for these structures (manholes).

Radwaste Building

The Radwaste Building is a Class II (non-safety-related) structure per UFSAR section 12.2.5. The Radwaste Building is a cellular box-type concrete structure extending approximately 20 feet below grade and 30 feet above grade and is supported by steel H-piles driven to bedrock. This building houses common services to all three units. The concrete structure provides shelter/protection and non-safety related structural support for equipment and components that support the processing of radwaste generated as a result of plant operation.

South Access Retaining Walls

These retaining walls are safety-related structural features that maintain the stability of the safety-related Earth Berm. The retaining walls provide retention of the Earth Berm and allows for removal of a portion of the earth berm to construct a temporary personnel access building. This temporary personnel access building provides access for site personnel into the unit 1 Reactor Building and a radiation control point for same entering or exiting the unit 1 Reactor Building during unit 1 recovery. These retaining walls are safety-related structural features and should be included in the LRA. Refer to Attachment 2 for the affected sections of the application with the required scoping, screening and aging management review results for this structural feature.

Water and Oil Storage Building

The Water and Oil Storage Building is a Class II (non-safety related) of light commercial construction, housing non-safety related electrical components and equipment for the non-safety related water and oil storage tanks located east of this building.

Part of Gate Structure No. 2 adjacent to Diesel HPFP House

Gate Structure No. 2 is part of the Auxiliary Condenser Cooling Water System as shown on UFSAR Figure 12.2-72a (TVA drawing 0-31E400-1). The system consists of waterways, control structures (i.e., Discharge Control Structure and Gate Structure No. 2) and cooling towers to permit helper system operation. They are seismically unclassified and were designed for normal applicable dead, live, and surcharge loads with appropriate load factors. The Diesel HPFP House is also a Class II structure and was determined to be in-scope for LR because it houses mechanical and electrical components that support the regulated event 50.48. Consequently seismic events do not have to be considered to occur with the regulated event 50.48.

Raw Water Treatment Facility

The Raw Water Treatment Facility is a Class II (non-safetyrelated) prefabricated facility housing non-safety-related equipment and tanks for chemical injection into the raw cooling and service water systems. The function of the facility is to provide shelter/protection and non-safety-related structural support for the equipment and

> components in this facility. A small office space for transit personnel is provided in one of the buildings.
>
> Structural Elements within the Transformer Yard and other miscellaneous buildings
>
> The Transformer Yard is in the scope of license renewal based on the criteria of 54.4(a)(3) for Station Blackout. See LRA section 2.4.7.4 for Transformer Yard scoping and screening results. Note that the 161 kV Switchyard (LRA section 2.4.7.5) and the 500 kV Switchyard (LRA section 2.4.7.6) are also in the scope of license renewal based on the criteria of 54.4(a)(3) for Station Blackout. There are no permanent buildings within the license renewal boundary diagram for Transformer Yard or 161 kV Switchyard or 500 kV Switchyard.

The staff reviewed the above response including the Attachments 1 and 2 of the applicant's letter dated January 24, 2005. The applicant committed to include the structural components discussed in these attachments. The staff provided its evaluation of the structures for isolation valve pits and south access retaining walls discussed in SER Sections 2.4.7.7 and 2.4.3.9, respectively. The staff found that the response is adequate and acceptable. Therefore, the staff's concern described in RAI 2.4-1 is resolved.

In RAI 2.4-4, dated December 20, 2004, the staff stated that LRA Table 2.4.2.1 presents a list of component types that are part of the reactor building, the auxiliary and emergency systems of the NSSS, the biological shield, the spent fuel pool, the steam dryer/moisture separator storage pool, the reactor cavity reactor auxiliary equipment, the steel superstructure with metal siding and the built-up roof. Therefore, the staff requested the applicant to provide a description of the "Neutron-Absorbing Sheets" used for the spent fuel storage racks and confirm that they are part of the spent fuel storage racks listed in LRA Table 2.4.2.1.

In its response, by letter dated January 24, 2005, the applicant stated:

> NUREG 1801, Section VII.A2.1-b, identifies "Spent Fuel Storage Racks – neutron absorbing sheets" as a component type. In BFN LRA Section 2.3.3.27 "Fuel Handling and Storage System (079)," it states that the spent fuel pool components are evaluated as structural components in Section 2.4.2.1 "Reactor Building Structure". BFN LRA Table 2.4.2.1 "Reactor Building Structure" identifies "Spent Fuel Storage Racks (includes new fuel storage racks)" as a component requiring aging management. The "Neutron Absorbing Sheet" is a component of the BFN spent fuel storage rack container tube wall and is comprised of Boral sandwiched within the stainless steel wall of each container tube.

The staff found the above response acceptable. Therefore, the staff's concern described in RAI 2.4-4 is resolved.

In RAI 2.4-5, dated December 20, 2004, referring to LRA Section 2.4.2.1, the staff requested the applicant to clarify if the reactor buildings are designed to maintain an internal negative pressure under neutral wind conditions in order to serve as the secondary containment whose primary purpose is to minimize the ground level release of airborne radioactive materials and to provide for a controlled, elevated release of the building atmosphere under accident conditions. If this assumption was correct, the staff wanted to know if reactor building pipe penetrations were provided with some type of silicone rubber seals that allow pipe movement and provide a seal between the pipe and the reactor buildings and maintain the negative internal pressure. The staff wanted the applicant to confirm that these penetration seals are included within the scope of licence renewal and are included in LRA Table 2.4.2.1.

In its response, by letter dated January 24, 2005, the applicant stated:

> With the exception of the Control Room, the Reactor Building is designed to maintain an internal negative pressure under neutral wind conditions in order to serve as the secondary containment whose primary purpose is to minimize the ground level release of airborne radioactive materials and to provide for a controlled, elevated release of the building atmosphere under accident conditions. The Control Room and portions of the Control Bay that are contained within the Reactor Building are maintained at a positive pressure to prevent the introduction of fission products during design basis events. Piping that is not anchored within a reinforced concrete wall is sealed with caulking or sealants. The reinforced concrete wall, and caulking and sealants are identified as component type "Reinforced Concrete Beams, Columns, Walls, and Slabs" and "Caulking & Sealants" respectively in Table 2.4.2.1 as requiring aging management review with a pressure boundary (PB) intended function.

The staff found the above response adequate and acceptable. Therefore, the staff's concern described in RAI 2.4-5 is resolved.

In RAI 2.4-12, dated December 20, 2004, the staff stated that based on information provided in LRA Sections 2.4.2.1, 2.4.2.2, 2.4.3.1, 2.4.4.1, and 2.4.7.1, it was unclear which cranes and hoists were determined to be within the scope of license renewal and which subset of the in-scope items have been screened in as items requiring an AMR. Therefore, the staff requested the applicant to clarify the treatment of cranes and hoists in the scoping and screening, and in the AMR. The applicant was requested to submit the following information:

- A list of all cranes, hoists, rails, and associated components in the scope of license renewal.
- Additional information to identify the location within the LRA where cranes, hoists, rails, and associated components are addressed. If these specific components are not considered to be within the scope of license renewal, provide the technical bases for their exclusion.
- A list of all cranes, hoists, rails, and associated components requiring an AMR (i.e., passive, long-lived components).
- A list of all cranes, hoists, rails, and associated components requiring aging management and/or TLAA.

In its response, by letter dated January 24, 2005, the applicant stated that the cranes and hoists are addressed in LRA Section 2.3.3.34 and the AMR results are contained in Table 3.3.2.34. This same question was asked in RAI 2.3.3.34-1, dated August 31, 2004. In its response to RAI 2.3.3.34-1 dated October 19, 2004, the applicant stated:

> The following buildings that contain NSR cranes and monorails which could potentially prevent safety related SSCs from performing their intended function(s) are: Reactor Building, Primary Containment, Diesel Generator Buildings, Intake Pumping Station, and Reinforced Concrete Chimney. All cranes and monorails in these buildings are in scope. The Mobile A-frames is a crane on wheels. The A-frame cranes are in scope since they could be used in a safety related building. This crane is subject to an AMR.

The staff found that the applicant had adequately responded to RAI 2.4-12 related to scoping and screening of cranes, hoists, rails, and associated components. Therefore, the staff's concern described in RAI 2.4-12 is resolved.

2.4.2.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reactor buildings components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reactor buildings components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.2 Equipment Access Lock

2.4.2.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.2, the applicant described the equipment access lock. The equipment access lock is a shared feature for all three reactor buildings. The equipment access lock is a reinforced concrete structure, supported on piles, located on the south end of the Unit 1 reactor building. The structure is sized to allow for the passage of a railcar or a tractor trailer within the structure. This allows for the transit of large equipment into, or out of, the reactor buildings, while maintaining the secondary containment. The equipment access lock is an airlock with large equipment doors that open to the outside environment on the south end, and allow access to the Unit 1 reactor building on the north end.

The equipment access lock contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the equipment access lock could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides controls for the potential release of fission products to the external environment
- provides a secondary containment envelope between the reactor building and the outside entrance
- provides structural support and shelter/protection for SR and NSR components
- provides flood protection barrier for internal and external flooding events

- provides a barrier for protection against internally or externally generated missiles
- provides a pressure boundary
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.2.2, the applicant identified the following equipment access lock component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- compressible joints and seals
- controlled leakage doors
- electrical and I&C penetrations
- mechanical penetrations
- piles
- reinforced concrete beams, columns, walls, and slabs
- structural steel beams, columns, plates, and trusses

2.4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.2 and UFSAR Sections 5.3.3.5 and 12.2.9 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.2.2.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the equipment access lock components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the equipment access lock components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Class 1 Group 3 Structures

In LRA Section 2.4.3, the applicant identified the structures and components of the Class 1 Group 3 structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the Class 1 Group 3 structures in the following sections of the LRA:

- 2.4.3.1 Diesel Generator Buildings
- 2.4.3.2 Standby Gas Treatment Building
- 2.4.3.3 Off-gas Treatment Building
- 2.4.3.4 Vacuum Pipe Building
- 2.4.3.5 Residual Heat Removal Service Water Tunnels
- 2.4.3.6 Electrical Cable Tunnel from the Intake Pumping Station to the Powerhouse
- 2.4.3.7 Underground Concrete Encased Structures
- 2.4.3.8 Earth Berm
- 2.4.3.9 South Access Retaining Walls (added LRA Section)

The corresponding subsections of the SER (2.4.3.1 – 2.4.3.9) present the staff's review findings with respect to the Class 1 Group 3 structures for BFN.

2.4.3.1 Diesel Generator Buildings

2.4.3.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.1, the applicant described the diesel generator buildings. The diesel generator buildings provide structural support and shelter/protection for the diesel generators (DGs) and other components within the scope of license renewal that are essential for the safe shutdown of the plant when there is a sustained loss of off-site power. The Unit 1 and 2 diesel generator building houses four DGs that provide power to the four shared Unit 1 and 2 shutdown boards that are located in the reactor buildings. The Unit 3 DG building houses four DGs that provide power to the four separate unit shutdown boards that are located in the Unit 3 DG building.

The diesel generator buildings contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the diesel generator buildings could prevent the satisfactory accomplishment of an SR function. In addition, the DG buildings perform functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components, and components that are relied upon to demonstrate compliance with the fire protection and SBO regulated events

- provides a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provides flood protection barrier for internal and external flooding events
- provides a barrier for protection against internally or externally generated missiles
- provides a pressure boundary
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.3.1, the applicant identified the following diesel generator building component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- compressible joints and seals
- controlled leakage doors
- fire barriers
- hatches/plugs
- masonry block
- metal siding
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs
- structural steel beams, columns, plates, and trusses

2.4.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.1 and UFSAR Sections 8.5, 12.2.8 and 12.2.13 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.1 identified an area in which additional information was required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-8, dated December 20, 2004, the staff stated that LRA Section 2.4.3.1 refers to Units 1 and 2 DG building and Unit 3 DG building. The license renewal drawing 0-10E201-01-LR shows a diesel generator building at the west side of the reactor building and another DG building at the east side, without indicating which DG building is designated for Units 1 and 2 shutdown function. The other building is intended for shutdown of the Unit 3 reactor. Therefore, the staff requested the applicant to clarify this ambiguity and explain why the four separate Unit 3 shutdown boards are located in Unit 3 DG building, whereas the other four shared Units 1 and 2 shutdown boards are located in the reactor buildings. Also regarding LRA Table 2.4.3.1, the applicant was asked to identify other items such as structural steel embedments, carbon steel boltings, reinforced concrete foundation footings, grouted concrete, and water proofing membrane materials that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> The original layout for Browns Ferry was a two unit site with a common Diesel Generator Building (DGB). Unit 3 was added after the initial design and provided with its own Diesel Generator Building and shutdown board rooms within the DGB. The following components are also located in the Units 1 and 2 Diesel Generator Building and Unit 3 Diesel Generator Building and are evaluated as Structures and Component Supports commodities in LRA Section 2.4.8:
>
> - ASME Equivalent Supports and Components
> - Cable Trays and Supports
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures
> - Equipment Supports and Foundations
> - HVAC Duct Supports
> - Instrument Line Supports
> - Instrument Racks, Frames, Panels, & Enclosures
> - Non-ASME Equivalent Supports and Components
> - Stairs, Platforms, Grating Supports
> - Tube Track

The applicant noted that in-scope components evaluated in LRA Section 2.4.8 also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including baseplate and grout) to the structure. Waterproofing membranes are not relied on to support the intended functions of the structural components of the BFN structures.

The staff found the above response provided sufficient information to clarify the ambiguity noted in RAI 2.4-8. Therefore, the staff's concern described in RAI 2.4-8 is resolved.

2.4.3.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the

DG buildings components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the diesel generator buildings components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.2 Standby Gas Treatment Building

2.4.3.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.2, the applicant described the SGT building. The SGT building houses shared components for all three units and provides a protected environment for the SGT system. The building consists of two double-barreled, reinforced concrete, box-frame structures with closed ends. The two structures are located side-by-side and adjacent to the southwest corner of the Unit 1 reactor building. The two structures also lie within the earth berm. One structure houses two SGT trains, and the other structure houses the remaining SGT train.

The SGT building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SGT building could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.3.2, the applicant identified the following SGT building component types that are within the scope of license renewal and subject to an AMR:

- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs

2.4.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.2 and UFSAR Sections 5.3 and 12.2.10 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.3.2.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the SGT building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the SGT building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.3 Off-Gas Treatment Building

2.4.3.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.3, the applicant described the off-gas treatment building. The off-gas treatment building is an underground structure that houses the off-gas system charcoal adsorbers and the supporting equipment for BFN. The exterior walls and bottom slab are designed and constructed to maintain their structural integrity if a partial collapse of the reinforced concrete chimney were to occur during an external event (i.e., seismic, tornadic, etc.). The maintained structural integrity would not permit water leakage into, or out of, the building below an elevation of 566.25 feet.

The portions of the off-gas treatment building containing components subject to an AMR include the exterior walls and bottom slab.

The off-gas treatment building contains SR components that are relied upon to remain functional during and following DBEs.

The intended functions within the scope of license renewal include the following:

- prevents the release of radiation into the surrounding groundwater from the failure or collapse of the activated charcoal beds
- provides a pressure boundary

In LRA Table 2.4.3.3, the applicant identified the following off-gas treatment building component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs

2.4.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.3 and UFSAR Section 12.2.14 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.3 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-9(a), dated December 20, 2004, the staff stated that LRA Section 2.4.3 lists several structures, that are not shown in drawing 0-10E201-01-LR. In LRA Section 2.4.3.3, the off-gas treatment building is described to have only exterior walls and bottom slab, implying that there is no top slab for the building. Therefore, the staff requested the applicant to confirm that the building has no top slab and no component types (e.g., electrical and I&C penetrations, structural steel embedments, carbon steel boltings, reinforced concrete foundation footings, grouted concrete, and water proofing membrane materials, etc.), other than those listed in LRA Table 2.4.3.3, that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> Section 2.4.3.3 of the LRA identifies the Off-Gas Treatment Building as an underground structure. The Off-Gas Treatment Building is an underground structure with exterior walls, interior walls and slabs, bottom or foundation slab and a top slab. The exterior walls and bottom slab are designed and constructed to maintain their structural integrity during a partial collapse of the Reinforced Concrete Chimney during a design basis event (tornado) so that they will not permit water leakage into or out of the building below elevation 566.25 feet (Reference UFSAR 12.2.14). The top slab is not required for the intended function of preventing release of radiation from the failure/collapse of the activated charcoal beds into the surrounding groundwater. Other than the "Caulking and Sealants," "Penetrations, Mechanical," and the "Reinforced Concrete Beams, Columns, Walls and Slabs" components noted on LRA Table 2.4.3.3, there are no other components that require an aging management review.

The staff found that the applicant had adequately responded to the part of RAI 2.4-9(a) related to the off-gas treatment building structure. Therefore the staff's concern described in RAI 2.4-9(a) is resolved.

2.4.3.3.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the off-gas treatment building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the off-gas treatment building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.4 Vacuum Pipe Building

2.4.3.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.4, the applicant described the vacuum pipe building. The vacuum pipe building is a structure shared by all of the units. It is located underground and provides structural support and shelter/protection for the condenser circulating water system vacuum breaker components. These components prevent backflow from the warm water channel into the intake channel. This ensures that the maximum temperature analysis assumptions, for accident cooling systems, are maintained during accidents and events.

The vacuum pipe building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the vacuum pipe building could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.3.4, the applicant identified the following vacuum pipe building component types that are within the scope of license renewal and subject to an AMR:

- hatches and plugs
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs

2.4.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.4 and UFSAR Section 12.2.7.8.3 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.4 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-9(b), dated December 20, 2004, the staff stated that LRA Section 2.4.3 lists several structures that are not shown in drawing 0-10E201-01-LR. Therefore, the staff requested the applicant to describe the specific location of the vacuum pipe building and confirm that there are no items such as structural steel embedments, carbon steel boltings, reinforced concrete foundation footings, grouted concrete, compressible joints and seals, waterproofing membrane and caulking materials that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> The vacuum pipe building is an underground structure accessed through a manhole and contains the condenser circulating water system vacuum breaker components that prevent back flow from the warm water channel to the intake channel (Reference UFSAR 12.2.7.8.3). The vacuum pipe building is an underground structure located south-east of the plant administration building as depicted on TVA drawing 0-10E201-01 and LR drawing 0-10E201-01-LR. The following components are also located in the vacuum pipe building and are evaluated as structures and component supports commodities in LRA Section 2.4.8:
>
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures
> - Non-ASME Equivalent Supports and Components

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-9(b) concerning the vacuum pipe building structure. Therefore, the staff's concern described in RAI 2.4-9(b) is resolved.

2.4.3.4.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the vacuum pipe building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the vacuum pipe building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.5 Residual Heat Removal Service Water Tunnels

2.4.3.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.5, the applicant described the RHRSW tunnels. The RHRSW tunnels are underground, multi-plate, arch tunnels that protect SR piping systems. This includes the RHRSW and EECW supply and discharge piping that penetrates the south wall of the reactor building and is buried, below grade, near the south end of the tunnel.

The failure of an NSR SSC in the RHRSW tunnel could prevent the satisfactory accomplishment of an SR function. The RHRSW tunnel also performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components, and components that are relied upon to demonstrate compliance with the fire protection regulated event
- prevents debris from entering a system or component
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.3.5, the applicant identified the following RHRSW tunnel component types that are within the scope of license renewal and subject to an AMR:

- compressible joints and seals
- electrical and I&C penetrations
- piles
- tunnels

2.4.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.5 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.5 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-9(c), dated December 20, 2004, the staff stated that LRA Section 2.4.3, Class 1 Group 3 Structures, lists several BFN structures that are not shown in drawing 0-10E201-01-LR. Therefore, the staff requested the applicant to describe the specific location of the RHRSW tunnels including their embedded boundaries in drawing 0-10E201-01-LR. The staff also requested the applicant to identify, as appropriate, items requiring an AMR that are part of the service water tunnels, such as structural steel embedments, carbon steel boltings, reinforced concrete beams, walls, slabs and foundation footings, grouted concrete, mechanical penetrations, waterproofing membrane and caulking materials.

In its response, by letter dated January 24, 2005, the applicant stated:

> The RHRSW tunnels are underground multi-plate arch tunnels that are buried in the earth berm. The north end of the tunnel terminates at the south wall of the reactor building. The south end of the tunnel is open to the outside on the south end of the earth berm. There are two tunnels for each reactor building. The following components are also located in the RHRSW tunnels and are evaluated as structures and component supports commodities in LRA Section 2.4.8:
>
> - ASME Equivalent Supports and Components
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures
> - Non-ASME Equivalent Supports and Components

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-9(c) related to the RHRSW structure. Therefore, the staff's concern described in RAI 2.4-9(c) is resolved.

2.4.3.5.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the RHRSW tunnels components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the RHRSW tunnels components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.6 Electrical Cable Tunnel from the Intake Pumping Station to the Powerhouse

2.4.3.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.6, the applicant described the electrical cable tunnel from the intake pumping station to the powerhouse, which is a Class I structure. The structure is an underground, concrete-encased tunnel that provides structural support and shelter/protection for power cables. These power cables are intended for components in the intake pumping station and include the RHRSW system, EECW system, and electric fire pumps. The tunnel runs east-west under the southern portion of the turbine buildings.

The electrical cable tunnel from the intake pumping station to the powerhouse structure contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the electrical cable tunnel from the intake pumping station to the powerhouse structure could prevent the satisfactory accomplishment of an SR function. In addition, the electrical cable tunnel from the intake pumping station to the powerhouse structure performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components, and components that are relied upon to demonstrate compliance with the fire protection regulated event
- provides a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.3.6, the applicant identified the following electrical cable tunnel component types that are within the scope of license renewal and subject to an AMR:

- fire barrier
- electrical and I&C penetrations
- tunnels

The electrical cable tunnel from the intake pumping station to the powerhouse is an underground concrete-encased tunnel that provides structural support and shelter/protection for the power cables for components (including the RHRSW System, EECW System, and the electric fire pumps) in the intake pumping station. The tunnel also runs east-west under the southern portion of the turbine buildings.

2.4.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.6 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.6 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-9(d), dated December 20, 2004, the staff stated that LRA Section 2.4.3, Class 1 Group 3 Structures, lists several structures that are not shown in drawing 0-10E201-01-LR. Therefore, the staff requested the applicant to describe the specific locations of the electrical cable tunnel from the intake pumping station to the powerhouse, including the portion running east-west under the southern portion of the turbine buildings. The staff also requested the applicant to identify items such as structural steel embedments, carbon steel boltings, reinforced concrete beams, walls, slabs, and foundation footings, grouted concrete, mechanical penetrations, and waterproofing membrane and caulking materials that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> The Electrical Cable Tunnel is an underground concrete encased tunnel that runs from the northwest corner of the Intake Pumping Station (IPS) to the southeast corner of the unit 3 Turbine Building and then east-west along the southern portion of the BFN Turbine Building. The following components are also located in the Electrical Cable Tunnel and are evaluated as Structures and Component Supports commodities in LRA Section 2.4.8:
>
> - Cable Trays and Supports
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-9(d) related to the electrical cable tunnel structure. Therefore, the staff's concern described in RAI 2.4-9(d) is resolved.

2.4.3.6.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the electrical cable tunnel components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the electrical cable tunnel components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.7 Underground Concrete Encased Structures

2.4.3.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.7, the applicant described the underground concrete encased structures. The underground concrete encased structures include SR manholes, handholes and duct banks that span between the SR structures, manholes, and handholes. This group of structures also includes those manholes, handholes, and duct banks that are required to support the SBO regulated event.

The underground concrete encased structures contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the underground concrete encased structures could prevent the satisfactory accomplishment of an SR function. In addition, the underground concrete encased structures performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components, and components that are relied upon to demonstrate compliance with the fire protection and SBO regulated events
- provides flood protection barrier for internal and external flooding events
- shelters and protects a component from the effects of weather or localized environmental conditions

- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.3.7, the applicant identified the following underground concrete encased structures component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- duct banks, manholes
- electrical and I&C penetrations
- penetrations, mechanical

2.4.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.3.7 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below

In RAI 2.4-9(e), dated December 20, 2004, the staff stated that LRA Section 2.4.3, Class 1 Group 3 structures lists several BFN structures on page 2.4-12 that are not shown in drawing 0-10E201-01-LR. Therefore, the staff requested the applicant to list the in-scope structures that have one or more of the underground concrete encased structures described in LRA Section 2.4.3.7. The staff also requested the applicant to identify items such as structural steel embedments, carbon steel boltings, reinforced concrete walls, slabs and foundation footings, grouted concrete, and waterproofing membrane that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated :

> The in-scope structures described in LRA Section 2.4.3.7 include the following:
>
> - Safety-related handhole (HH) No. 16, located in the yard area north-west of the Intake Pumping Structure (IPS) and safety-related handhole (HH) No. 26, located in the yard area north-east of the Unit 3 Diesel Generator Building (DGB) and south of Condensate Storage Tanks Nos. 1, 2, and 3.

- Safety-related concrete duct bank (inaccessible) that spans from the Unit 1 & 2 Diesel Generator Building to the Standby Gas Treatment Building, safety-related concrete duct bank (inaccessible) that spans from the IPS to HH No. 16 to HH No. 26 and to the Electrical Cable Tunnel from the IPS to the Powerhouse, SR concrete duct bank (inaccessible) that spans from the unit 3 Diesel Generator Building to the Electrical Cable Tunnel from the IPS to the Powerhouse, and the safety-related concrete duct bank (inaccessible) that spans from the Containment Atmosphere Dilution Storage Tank's A and B foundations to the Reactor Building.
- Manholes A and B which provide access to the concrete tunnel located in the 161 kV and 500 kV Switchyards that support the 10 CFR 54.4(a)(3) SBO regulated event. NOTE: The concrete tunnel located in the 161 kV and 500 kV switchyards is within the scope of license renewal and identified in LRA ections 2.4.7.5 and 2.4.7.6, respectively, as component type tunnels.
- Handholes 1 - 13 and associated duct banks (inaccessible) located in the transformer yard on the north side of the Turbine Building that support the 10 CFR 54.4(a)(3) SBO regulated event.
- The following components are also located in the Underground Concrete Encased Structures and are evaluated as Structures and Component Supports commodities in LRA Section 2.4.8:
  - Cable Trays and Supports
  - Conduit and Supports
  - Electrical Panels, Racks, Cabinets, and Other Enclosures
  - Non-ASME Equivalent Supports and Components

The applicant also noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-9(e) related to underground concrete encased structures. Therefore, the staff's concern described in RAI 2.4-9(e) is resolved.

2.4.3.7.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the underground concrete encased structures components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the underground concrete encased structures components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3.8 Earth Berm

2.4.3.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.3.8, the applicant described the earth berm. The earth berm is classified as an SR earthen embankment and is common to BFN. The earth berm extends along the west, south, and east walls of the reactor building from the Unit 1 DG building to the Unit 3 DG building. The equipment access lock, the RHRSW tunnels, the vent vaults, and the SGT building are all located within the earth berm.

The earth berm contains SR components that are relied upon to remain functional during and following DBEs.

The intended function, within the scope of license renewal, is to provide structural and functional support for in-scope structures and features.

In LRA Table 2.4.3.8, the applicant identified the following earth berm component type that is within the scope of license renewal and subject to an AMR:

- intake canals, dikes, embankments

2.4.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3.8 and UFSAR Sections 12.2.9 and 12.2.10 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.3.8.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the earth berm components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the earth berm components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

Section 2.4.3.9. In earlier RAI 2.4-1 response, dated January 24, 2005, the applicant stated that the south access retaining walls were inadvertently omitted. The retaining walls are SR structural features that maintain the stability of the earth berm, therefore are included in the scope of license renewal. In Attachment 2 to its letter, the applicant added LRA Section 2.4.3.9, as discussed below.

2.4.3.9 South Access Retaining Walls

In added LRA Section 2.4.3.9, the applicant described the south access retaining walls. The south access retaining walls are required to support the existing earth berm for the construction of a new temporary access building. This access building will allow Unit 1 recovery personnel entry into the Unit 1 reactor building during the recovery of Unit 1. These retaining walls have been classified as SR to match the safety function of the earth berm. These retaining walls are located east of the equipment access lock.

The south access retaining walls contain SR components that are relied upon to remain functional during and following DBEs.

The intended function, within the scope of license renewal, is to provide structural and functional support, for in-scope structures and components, by an SR component.

In added LRA Table 2.4.3.9, the applicant identified the reinforced concrete beams, columns, walls, and slabs component type that is within the scope of license renewal and subject to an AMR.

2.4.3.9.2 Staff Evaluation

The staff reviewed added LRA Section 2.4.3.9 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the added section of the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.3.9.3 Conclusion

The staff reviewed the added LRA Section 2.4.3.9 and related structural/component information to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the south access retaining walls components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant had adequately identified the south access retaining walls components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Class 1 Group 6 Structures

In LRA Section 2.4.4, the applicant identified the structures and components of the Class 1 Group 6 structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the Class 1 Group 6 structures in the following sections of the LRA:

- 2.4.4.1 intake pumping station
- 2.4.4.2 gate structure No. 3
- 2.4.4.3 intake channel
- 2.4.4.4 north bank of cool water channel east of gate structure No. 2
- 2.4.4.5 south dike of cool water channel between gate structure Nos. 2 and 3

The corresponding subsections of the SER, 2.4.4.1 – 2.4.4.5, present the staff's review findings with respect to the Class 1 Group 6 structures.

2.4.4.1 Intake Pumping Station

2.4.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.4.1, the applicant described the intake pumping station, which is a Class 1 structure constructed of reinforced concrete. The intake pumping station houses components for BFN and provides structural support and shelter/protection for the condenser circulating water pumps, the electric fire pumps, and the pumps that supply the RHRSW and the EECW systems. The station also protects SR equipment and components, such as the pumps supplying the RHRSW and EECW systems, from design-basis events such as earthquakes, floods, and tornadoes.

The intake pumping station contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the intake pumping station could prevent the satisfactory accomplishment of an SR function. In addition, the intake pumping station performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components, and components relied upon to demonstrate compliance with the fire protection and SBO regulated events
- provides a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provides a flood protection barrier for internal and external flooding events
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal

- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.4.1, the applicant identified the following intake pumping station component types that are within the scope of license renewal and subject to an AMR:

- caulking and sealants
- compressible joints and seals
- controlled leakage doors
- fire barriers
- masonry block
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs
- structural steel beams, columns, plates, and trusses

2.4.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4.1 and UFSAR Sections 12.2.7 and 12.2.16 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.4.1 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-10(a), dated December 20, 2004, the staff requested the applicant to provide additional information regarding the intake pumping station structure. Specifically, the RAI requested the applicant to identify, as applicable, items such as hatches and plugs, structural steel embedments, carbon steel boltings, reinforced concrete foundation footings, grouted concrete, and waterproofing membrane materials that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> The following components are also located in the intake pumping station and are evaluated as structures and component supports commodities in LRA Section 2.4.8:
>
> - ASME Equivalent Supports and Components
> - Cable Trays and Supports
> - Conduit and Supports

- Electrical Panels, Racks, Cabinets, and Other Enclosures
- Equipment Supports and Foundations
- Instrument Line Supports
- Non-ASME Equivalent Supports and Components
- Stairs, Platforms, Grating Supports
- Tube Track

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-10(a) related to the intake pumping station structure. Therefore, the staff's concern described in RAI 2.4-10(a) is resolved.

2.4.4.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the intake pumping station components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the intake pumping station components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4.2 Gate Structure No. 3

2.4.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.4.2, the applicant described the gate structure No. 3, which is a Class 1 structure common to all three of the units. The structure acts as a skimmer wall for water drawn from Wheeler Reservoir and used in the plant for cooling. Gate structure No 3 is designed so that a sufficient flow of water from Wheeler Reservoir is provided to the intake channel, in order to supply the RHRSW and the EECW systems. Gate structure No. 3 is located at the southeast end of the plant, below the intake pumping station and the intake channel.

Gate structure No. 3 contains SR components that are relied upon to remain functional during and following DBEs. In addition, gate structure No. 3 performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- ensures a source of cooling water to SR components

- ensures a source of cooling water to components relied upon to demonstrate compliance with the fire protection and SBO events
- provides for flow distribution
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.4.2, the applicant identified the following gate structure No. 3 component types that are within the scope of license renewal and subject to an AMR:

- piles
- reinforced concrete beams, columns, walls, and slabs
- structural steel beams, columns, plates, and trusses

2.4.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4.2 and UFSAR Sections 11.6 and 12.2.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.4.2.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the gate structure No. 3 components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the gate structure No. 3 components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4.3 Intake Channel

2.4.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.4.3, the applicant described the intake channel, which is common to all three units and provides an excavated channel that extends from the intake pumping station to the river channel that would exist if the Wheeler Dam failed. The channel provides a source of water to the condenser circulating water system and the other plant cooling systems during normal operation. The channel also provides a source of cooling water, post-transient and post-accident, for decay heat removal, containment cooling, spent fuel cooling, control bay cooling, essential equipment cooling, and fire protection. In addition, the channel can provide sufficient flow and heat sink capacity to maintain a safe shutdown following a failure of the downstream Wheeler Dam.

The intake channel contains SR components that are relied upon to remain functional during and following DBEs. In addition, the intake channel performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- ensures a source of cooling water to SR components
- ensures a source of cooling water to components relied upon to demonstrate compliance with the fire protection and SBO events
- provides a source of cooling water
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.4.3, the applicant identified the following intake channel component type that is within the scope of license renewal and subject to an AMR:

- intake canals, dikes, embankments

2.4.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4.3 and UFSAR Sections 2.4.2 and 12.2.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.4.3.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the intake channel components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the intake channel components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4.4 North Bank of the Cool Water Channel East of Gate Structure No. 2

2.4.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4.4, the applicant described the north bank of the cool water channel east of gate structure No. 2. The structure is an earthen embankment that is located on the north side of the cool water channel and south of the reactor buildings. The structure is SR, with a sloped portion protected by vegetation and rock rip-rap. The bank is designed to protect the buried RHRSW system discharge piping that is located within the bank that discharges into the Wheeler Reservoir.

The north bank of the cool water channel east of gate structure No. 2 contains SR components that are relied upon to remain functional during and following DBEs. In addition, the structure performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides for structural support of the buried SR components, namely piping, and components relied upon to demonstrate compliance with the fire protection and SBO regulated events
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.4.4, the applicant identified the following component type in the north bank of the cool water chanel east of gate structure No. 2 that is within the scope of license renewal and subject to an AMR:

- intake canals, dikes, embankments

2.4.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4.4 and UFSAR Section 12.2.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.4.4.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the components of the north bank of the cool water channel east of gate structure No. 2 that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the components of the north bank of the cool water channel east of gate structure No. 2 that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4.5 South Dike of Cool Water Channel between Gate Structure Nos. 2 and 3

2.4.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.4.5, the applicant described the south dike of the cool water channel between gate structure Nos. 2 and 3. The structure is an earthen dike that is located on the south side of the cool water channel and forms a boundary with the Wheeler Reservoir on the north side. The dike is an SR earthen structure that has a sloped portion that is protected with vegetation and rock rip-rap. The dike is designed to protect the buried RHRSW system discharge piping that is located within the dike and that discharges into Wheeler Reservoir.

The portions of the south dike of cool water channel between gate structure Nos. 2 and 3 structure containing components subject to an AMR are those portions located above the RHRSW system discharge piping.

The south dike of the cool water channel between gate structure Nos. 2 and 3 contains SR components that are relied upon to remain functional during and following DBEs. In addition, the dike performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support of buried SR components, namely piping, and components relied upon to demonstrate compliance with the fire protection and SBO regulated events
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.4.5, the applicant identified the following component types in the south dike of cool water channel between gate structure Nos. 2 and 3 that are within the scope of license renewal and subject to an AMR:

- intake canals, dikes, embankments

2.4.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4.5 and UFSAR Section 12,2.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.4.5 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-6, dated December 20, 2004, the staff stated that the LRA Section 2.4.4.5 states that the portion of the structure that contains components requiring an AMR is the portion above the RHRSW system discharge piping. Therefore, the staff requested applicant to clarify if the entire south dike of cooling water channel between gate structure Nos. 2 and 3, or only the portion indicated, is designated to be within the scope requiring an AMR. The staff also stated that, if the applicant scoped only a portion of the south dike structure as requiring an AMR, the staff wanted the applicant to discuss the basis for narrowing the scope. The staff required the applicant to clearly define the boundary within the AMR scope.

In its response, by letter dated January 24, 2005, the applicant stated:

> Only the portion of the south dike of the cool water channel between gate structure Nos. 2 and 3 above the RHRSW discharge piping system plus approximately 30 feet on either side of the piping is within the scope of License Renewal and requires an AMR. The earthen dike provides a structural support intended function as noted in LRA Table 2.4.4.5 for the RHRSW discharge piping system and that portion of the dike has been qualified for a seismic event.

The staff found the above clarification provided by the applicant adequate and acceptable. The staff's concern described in RAI 2.4-6 is resolved.

2.4.4.5.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the components in the south dike of the cool water channel between gate structure Nos. 2 and 3 that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the components in the south dike of the cool water channel between gate structure Nos. 2 and 3 that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.5 Class 1 Group 8 Structures

In LRA Section 2.4.5, the applicant identified the structures and components of the Class 1 Group 8 structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the Class 1 Group 8 structures in the following sections of the LRA:

- 2.4.5.1 condensate water storage tanks' foundations and trenches
- 2.4.5.2 containment atmosphere dilution storage tanks' foundations

The corresponding subsections of the SER 2.4.5.1 – 2.4.5.2, present the staff's review findings with respect to the Class 1 Group 8 structures for BFN.

2.4.5.1 Condensate Water Storage Tanks' Foundations and Trenches

2.4.5.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.5.1, the applicant described the condensate water storage tanks' foundations and trenches. The condensate water storage tanks' foundations and trenches are a shared feature for BFN. Five 500,000-gallon capacity tanks are supported on reinforced concrete ring foundations or on reinforced concrete slabs, on grade, with a sand bed. Only condensate water storage tank Nos. 1, 2, and 3 are within the scope of license renewal. Therefore, the foundations, trenches, and components for these tanks are also within the scope of license renewal.

The condensate water storage tanks' foundations and trenches are concrete structures that provide structural support to ensure that the condensate water storage tanks can provide: (1) a source of water makeup to the condenser hotwells and the CRD hydraulic system, during normal operations; (2) high purity water for miscellaneous makeup uses throughout the plant (e.g., demineralizer backwash and spent fuel pool makeup); and (3) a source of clean water to the HPCI and RCIC systems, when required for test; for reactor vessel makeup during accidents and regulated events; and to the core spray systems, when required for test.

The foundations and trenches for the three condensate water storage tanks that provide the normal water supply to the units, contain components requiring an AMR.

The condensate water storage tanks' foundations and trenches contain SR components that are relied upon to remain functional during and following DBEs. In addition, the condensate water storage tanks' foundations and trenches perform functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides physical support and shelter/protection for components that are relied upon to demonstrate compliance with the fire protection and SBO regulated events
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.5.1, the applicant identified the following condensate water storage tanks' foundations and trenches component types that are within the scope of license renewal and subject to an AMR:

- equipment supports and foundations
- electrical and I&C penetrations
- mechanical penetrations
- structural steel beams, columns, plates, and trusses
- trenches

2.4.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5.1 and UFSAR Section 11.9 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.5.1 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-10(b), dated December 20, 2004, the applicant was asked to provide additional information regarding the condensate water storage tank's foundation and trenches. The staff also requested the applicant to confirm that the equipment supports and foundations as well as the trenches listed in LRA Table 2.4.5.1 consist of reinforced concrete components and to identify items such as structural steel embedments, carbon steel boltings, grouted concrete, and waterproofing membrane materials that require an AMR.

In its response, by letter dated January 24, 2005, the applicant stated:

> Regarding the Condensate Water Storage Tank's Foundation and Trenches, "Equipment Supports and Foundations" as well as "Trenches" components listed in Table 2.4.5.1 consist of reinforced concrete and this is confirmed in Table 3.5.2.17 of the LRA. Note that the Condensate Storage Tanks are supported on a reinforced concrete ring foundation and the earthen fill material (rock and sand) inside the ring is identified as Item 1 of Table 3.5.2.17. The following components are also located on the Condensate Water Storage Tanks Foundations and Trenches and are evaluated as Structures and Component Supports commodities in LRA Section 2.4.8:
>
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures
> - Instrument Racks, Frames, Panels, & Enclosures
> - Non-ASME Equivalent Supports and Components

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-10(b) related to the condensate water storage tanks' foundations and trenches structures. Therefore, the staffs concern described in RAI 2.4-10(b) is resolved.

2.4.5.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the condensate water storage tanks' foundations and trenches components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the condensate water storage tanks' foundations and trenches components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.5.2 Containment Atmosphere Dilution Storage Tanks' Foundations

2.4.5.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.5.2, the applicant described the CAD storage tanks' foundations. The tanks' foundations are reinforced concrete slabs on grade, or foundations, that provide structural support for the tanks. These tanks are used by the CAD system to control the concentration of combustible gases in the primary containment after an accident, and to provide a backup pneumatic supply to selected components when the control air system is unavailable.

The CAD system storage tanks' foundations contain SR components that are relied upon to remain functional during and following DBEs. In addition, the CAD storage tanks' foundations perform functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support for SR components and components relied upon to demonstrate compliance with the fire protection and SBO regulated events
- provides structural and functional support for structures and components within the scope of license renewal

In LRA Table 2.4.5.2, the applicant identified the following CAD storage tanks' foundations component types that are within the scope of license renewal and subject to an AMR:

- equipment supports and foundations.

2.4.5.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5.2 and UFSAR Section 5.2.6 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.5.2 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-7, dated December 20, 2004, the staff stated that in LRA Section 2.4.5.2, the applicant discussed the screening results of the CAD storage tank's foundations. Therefore, for items included in LRA Table 2.4.5.2, the staff requested the applicant to identify other items that require an AMR, such as structural steel embedments, carbon steel boltings, reinforced concrete slabs and foundation footings, and grouted concrete.

In its response, by letter dated January 24, 2005, the applicant stated:

> The reinforced concrete foundation slab for the Containment Atmosphere Dilution (CAD) Storage Tank's Foundation is included as part of the "Equipment Supports and Foundation" component type in Table 2.4.5.2. CAD Storage Tank's Foundation is a reinforced concrete foundation slab on grade that provides structural support for the tank of the CAD system.

The following components are also located on the CAD storage tank foundation and are evaluated as part of the structures and component supports commodity group in LRA Section 2.4.8:

- Electrical Panels, Racks, Cabinets, and Other Enclosures
- Conduits and Supports
- Non-ASME Equivalent Supports and Components
- Instrument Racks, Frames, Panels, & Enclosures

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure.

The staff found that the response adequately clarified LRA Section 2.4.5.2. Therefore, the staff's concern described in RAI 2.4-7 is resolved.

2.4.5.2.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the CAD storage tanks' foundations components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the CAD storage tanks' foundations components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.6 Class 1 Group 9 Structures

2.4.6.1 Reinforced Concrete Chimney

2.4.6.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.6.1, the applicant described the reinforced concrete chimney structure, which is a Class 1 structure that serves all three units. The chimney is 600 feet in elevation and provides an elevated release point for radioactive gases. These radioactive gases are released from the gaseous radwaste processing systems during normal plant operations. They are also released from the SGT system during secondary containment isolation and during primary containment venting. The hardened wetwell vent systems also release gaseous radwaste, following design-basis accidents. The system is designed so that Class 1 structures (with the exception of the off-gas treatment building) will not be damaged during DBEs.

The reinforced concrete chimney contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the reinforced concrete chimney could prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for SR and NSR components
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support for structures and components within the scope of license renewal
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.6.1, the applicant identified the following reinforced concrete chimney component types that are within the scope of license renewal and subject to an AMR:

- hatches and plugs
- metal roofing
- electrical and I&C penetrations
- mechanical penetrations
- reinforced concrete beams, columns, walls, and slabs
- roofing membrane
- structural steel beams, columns, plates, and trusses

2.4.6.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.6.1 and UFSAR Section 12.2.4 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.6.1.3 Conclusion

The staff reviewed the LRA and related structural components to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the reinforced concrete chimney components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the reinforced concrete chimney components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7 Non-Class 1 Structures

In LRA Section 2.4.7, the applicant identified the structures and components of the non-Class 1 structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the non-Class 1 structures in the following sections of the LRA:

- 2.4.7.1 Turbine Buildings
- 2.4.7.2 Diesel High Pressure Fire Pump House
- 2.4.7.3 Vent Vault
- 2.4.7.4 Transformer Yard
- 2.4.7.5 161 kV Switchyard
- 2.4.7.6 500 kV Switchyard
- 2.4.7.7 Isolation Valve Pits (added LRA Section)
- 2.4.7.8 Radwaste Building (added LRA Section)
- 2.4.7.9 Service Building (added LRA Section)

The corresponding subsections of the SER, 2.4.7.1 – 2.4.7.6, present the staff's review findings with respect to the non-Class 1 structures for BFN.

2.4.7.1 Turbine Buildings

2.4.7.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.1, the applicant described the turbine buildings. The turbine buildings are a common Class II structure that consist of a reinforced concrete structure with a steel superstructure. The buildings are compartmentalized; the primary consideration for the design of the walls within the buildings is for radiation shielding. The turbine buildings provide structural support and shelter/protection for components required for safe shutdown following the SBO and fire protection regulated events. The buildings also provide support and shelter/protection for the outboard main steam isolation valves leakage pathway to condenser.

The failure of NSR SSCs in the turbine buildings could prevent the satisfactory accomplishment of an SR function. The turbine buildings also perform functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for the outboard main steam isolation valves leakage pathway to condenser
- not adversely impact other Class I structures as a result of a DBE
- provides structural support and shelter/protection for components relied upon to demonstrate compliance with the SBO and fire protection regulated events
- shelters and protects a component from the effects of weather or localized environmental conditions

- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.7.1, the applicant identified the following turbine buildings component types that are within the scope of license renewal and subject to an AMR:

- hatches/plugs
- metal roofing
- masonry block (within scope for Unit 2 only)
- electrical and I&C penetrations
- mechanical penetrations
- piles
- reinforced concrete beams, columns, walls, and slabs
- roof membrane
- structural steel beams, columns, plates and trusses

2.4.7.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.1 and UFSAR Section 12.2.3 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.1 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4 -11(a), the applicant was requested to provide additional information regarding the turbine buildings. The staff also requested the applicant to explain the basis for stating that masonry block utilized for Units 1 and 3 is not in scope for the period of extended operation. The staff further requested the applicant to identify items that require an AMR, such as structural steel embedments, carbon steel boltings, grouted concrete, metal sidings, and waterproofing membrane materials.

In a letter dated January 24, 2005, the applicant responded as follows:

> The masonry wall in the unit 2 Turbine Building provides a structural NSR support intended function for cable tray supports for cables required to support the off-site AC recovery for SBO requirements. The SBO cables are routed through the unit 2 Turbine Building in a cable gallery with walls constructed of masonry block, to the north end of the unit 2 Turbine Building, and then to a concrete tunnel buried in the yard north of the Turbine Building. The concrete tunnel provides access to the 161 kV and 500kV

Switchyards. Only the unit 2 Turbine Building masonry walls are in scope due to the unique cable gallery to tunnel routing of the cables required to support the off-site AC recovery for SBO requirements for all units. This unique cable gallery does not exist in the unit 1 or 3 Turbine Buildings.

The following components are also located in the BFN Turbine Buildings and are evaluated as Structures and Component Supports commodities in LRA section 2.4.8:

- ASME Equivalent Supports and Components
- Cable Trays and Supports
- Conduit and Supports
- Electrical Panels, Racks, Cabinets, and Other Enclosures
- Equipment Supports and Foundations
- Instrument Racks, Frames, Panels, & Enclosures
- Non-ASME Equivalent Supports and Components
- Stairs, Platforms, Grating Supports

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4 -11(a) related to the turbine buildings structures. Therefore, the concern described in RAI 2.4-11(a) is resolved.

2.4.7.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the turbine buildings components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the turbine buildings components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.2 Diesel High Pressure Fire Pump House

2.4.7.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.2, the applicant described the diesel high pressure fire pump house. The diesel high pressure fire pump house is a shared structure for BFN. The pump house provides structural support and shelter/protection for the diesel high pressure fire pump.

The entire diesel high pressure fire pump house contains components that are subject to an AMR. The diesel high pressure fire pump house performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for components relied upon to demonstrate compliance with the fire protection regulated event
- prevents debris from entering a system or component
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.7.2, the applicant identified the following diesel high pressure fire pump house component types that are within the scope of license renewal and subject to an AMR:

- metal roofing
- metal siding
- electrical and I&C penetrations
- mechanical penetrations
- piles
- reinforced concrete beams, columns, walls, and slabs
- roof membrane
- structural steel beams, columns, plates, and trusses

2.4.7.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.2 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.2 identified area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4 -11(b), dated December 20, 2004, the staff requested the applicant to identify items that require an AMR, such as structural steel embedments, carbon steel boltings, grouted concrete, and waterproofing membrane materials.

In its response, by letter dated January 24, 2005, the applicant stated:

> The following components are also located in the diesel high pressure fire pump house and are evaluated as structures and component supports commodities in LRA section 2.4.8:
>
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures
> - Equipment Supports and Foundations
> - Non-ASME Equivalent Supports and Components

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4 -11(b) related to the diesel high pressure fire pressure fire pump house structure. Therefore, the staff's concern described in RAI 2.4-11(b) is resolved.

2.4.7.2.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the diesel high pressure fire pump house components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the diesel high pressure fire pump house components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.3 Vent Vaults

2.4.7.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.3, the applicant described the vent vaults. A vent vault is provided for each unit. Each vent vault is a concrete structure with an open top. The base foundation for each vent vault is founded on compacted backfill that is located within the earth berm and adjacent to the respective reactor building. The vent vaults contain components required for the reactor building ventilation system supply, including the secondary containment isolation dampers.

The portions of the vent vaults containing components subject to an AMR include the east and west walls and the floor slab. The failure of NSR systems, SSCs in the vent vaults could prevent the satisfactory accomplishment of an SR function.

The intended function within the scope of license renewal is to provide structural and functional support for in-scope structures and components by an NSR component.

In LRA Table 2.4.7.3, the applicant identified the following vent vaults component types that are within the scope of license renewal and subject to an AMR:

- reinforced concrete beams, columns, walls, and slabs

2.4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.3 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.3 identified area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-9(a), dated December 20, 2004, the staff stated that LRA Section 2.4.3 lists several structures that are not shown in drawing 0-10E201-01-LR. Therefore, the staff requested the applicant to clarify the reason why the three vent vaults shown in drawing 0-10E201-01-LR do not indicate the specific systems or components contained or sheltered within them. Additionally, the applicant was requested to identify items that require an AMR, such as structural steel embedments, carbon steel boltings, grouted concrete, and waterproofing membrane materials.

In its response, by letter dated January 24, 2005, the applicant stated:

> The three vent vaults are open-top concrete structures located within the earth berm adjacent to their associated reactor building. The vent vaults contain components required for the reactor building ventilation system supply, including the secondary containment isolation dampers. Other than the "Reinforced Concrete Beams, Columns, Walls and Slabs" noted on LRA Table 2.4.7.3, they contain no components that require an aging management review.

The staff found that the applicant had adequately responded to RAI 2.4-9(a) on the vent vaults structure. Therefore, the staff's concern described in RAI 2.4-9(a) is resolved.

2.4.7.3.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the vent vaults components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the vent vaults components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.4 Transformer Yard

2.4.7.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.4, the applicant described the transformer yard. The transformer yard is a shared feature for all three units. The transformer yard supports components required for power restoration following the SBO regulated event.

The transformer yard performs functions that support SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support for components relied upon to demonstrate compliance with the SBO regulated event
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.7.4, the applicant identified the following transformer yard component types that are within the scope of license renewal and subject to an AMR:

- piles
- structural steel beams
- structural columns
- structural plates
- structural trusses

2.4.7.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.4 and UFSAR Sections 8.2, 8.4 and 8.10 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.4 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.4 -11(d), dated December 20, 2004, the staff requested the applicant, with respect to the transformer yard, to identify, items such as structural steel embedments, carbon steel plates and boltings, reinforced concrete pads and footings, grouted concrete, and waterproofing membrane materials that require an AMR.

In its response by letter, dated January 24, 2005, the applicant stated:

> The following components are also located in the BFN Transformer Yard, and are evaluated as Structures and Component Supports commodities in LRA section 2.4.8:
>
> - Equipment Supports and Foundations

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-11(d) related to the transformer yard structure. Therefore, the staff's concern described in RAI 2.4-11(d) is resolved.

2.4.7.4.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the transformer yard components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the transformer yard components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.5 161 kV Switchyard

2.4.7.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.5, the applicant described the 161 kV switchyard, which is a shared feature for all three units. The switchyard routes power from offsite transmission lines into BFN for onsite use. The 161 kV switchyard supports components required for power restoration following the SBO regulated event.

The 161 kV switchyard performs functions that support SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for components that are relied upon to demonstrate compliance with the SBO regulated event
- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.7.5, the applicant identified the following 161 kV switchyard component types that are within the scope of license renewal and subject to an AMR:

- structural steel beams
- structural columns
- structural plates
- structural trusses
- tunnels

2.4.7.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.5 and UFSAR Sections 1.5,1.6, 8.1, 8.3, 8.4, and 8.10 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.5 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4 -11(d)(2), dated December 20, 2004, the staff requested the applicant to identify items that require an AMR, such as structural steel embedments, carbon steel plates and boltings, reinforced concrete pads and footings, grouted concrete, and waterproofing membrane materials.

In its response, by letter January 24, 2005, the applicant stated:

> The following components are also located in the BFN 161 kV Switchyard and are evaluated as Structures and Component Supports commodities in LRA section 2.4.8:
>
> - Equipment Supports and Foundations
> - Cable Trays and Supports
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-11(d) related to the 161 kV switchyard structure. Therefore, the staff's concern described in RAI 2.4-11(d) is resolved.

2.4.7.5.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the 161 kV switchyard components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the 161 kV switchyard components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.6 500 kV Switchyard

2.4.7.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.6, the applicant described the 500 kV switchyard. The 500 kV switchyard is a shared feature for all three units. The switchyard routes power to offsite transmission lines and can be used to route power into BFN for onsite use. The 500 kV switchyard supports components required for power restoration following an SBO regulated event.

The 500 kV switchyard performs functions that support SBO.

The intended functions within the scope of license renewal include the following:

- provides structural support and shelter/protection for components that are relied upon to demonstrate compliance with the SBO regulated event
- shelters and protects a component from the effects of weather or localized environmental conditions

- provides structural and functional support, for in-scope structures and components, by an NSR component

In LRA Table 2.4.7.6, the applicant identified the following 500 kV switchyard component types that are within the scope of license renewal and subject to an AMR:

- structural steel beams
- structural columns
- structural plates
- structural trusses
- tunnels

2.4.7.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.6 and UFSAR Sections 1.5, 1.6, 8.1, 8.3, 8.4, and 8.10 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.7.4.6 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-11(d)(3), dated December 20, 2004, the staff requested the applicant to identify items that require an AMR, such as structural steel embedments, carbon steel plates and boltings, reinforced concrete pads and footings, grouted concrete, and waterproofing membrane materials.

In its response, by letter, dated January 24, 2005, the applicant stated:

> The following components are also located in the BFN 500 kV Switchyard and are evaluated as Structures and Component Supports commodities in LRA section 2.4.8:
>
> - Equipment Supports and Foundations
> - Cable Trays and Supports
> - Conduit and Supports
> - Electrical Panels, Racks, Cabinets, and Other Enclosures

The applicant noted that for in-scope components evaluated in LRA Section 2.4.8, the components also include support structural members, welds, bolting, anchorage and building concrete at anchorage (including base plate and grout) to the structure. Waterproofing membranes are not relied upon to support the intended functions of the structural components of BFN structures.

The staff found that the applicant had adequately responded to RAI 2.4-11(d) related to the 500 kV switchyard structure. Therefore, the staff's concern described in RAI 2.4-11(d) is resolved.

2.4.7.6.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the 500 kV switchyard components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the 500 kV switchyard components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

Section 2.4.7.7. In earlier RAI 2.4-1 response, dated January 24, 2005, the applicant stated that isolation valve pits are Class II NSR structures that provide structural support and shelter protection for the hardened wetwell vent piping and components. Since these isolation valve pits provide an intended function for an in scope mechanical system, therefore, are included within the scope of license renewal. In Attachment 1 to its letter, the applicant added LRA Section 2.4.7.7, as discussed below.

2.4.7.7 Isolation Valve Pits

2.4.7.7.1 Summary of Technical Information in the Application

In added LRA Section 2.4.7.7, the applicant described the isolation valve pits, stating that there is an isolation valve pit for each unit.

The failure of NSR SSCs in the isolation valve pits could potentially prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- shelters and protects a component from the effects of weather or localized environmental conditions
- provides structural and functional support, for in-scope structures and components, by an NSR component

In added LRA Table 2.4.7.7, the applicant identified the following isolation valve pits component types that are within the scope of license renewal and subject to an AMR:

- caulking & sealants
- penetrations electrical and I&C
- penetrations mechanical

- reinforced concrete beams, columns, walls, and slabs
- structural steel beams, columns, plates, and trusses

2.4.7.7.2 Staff Evaluation

The staff reviewed added LRA Section 2.4.7.7 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the added section of the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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).

2.4.7.7.3 Conclusion

The staff reviewed the added LRA Section 2.4.7.7 and related structural/component information to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the isolation valve pits components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant had adequately identified the isolation valve pits components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

Sections 2.4.7.8 and 2.4.7.9. The staff, in an earlier RAI 2.1-2A(3) dated September 3, 2004, requested additional information related to seismic Class I piping boundaries for identifying additional piping segments and supports/equivalent anchors that need to be placed in the scope of license renewal to satisfy the 10 CFR 54.4(a)(2) criterion. The staff had asked whether if this review brought into scope any new buildings not in the original application. By response dated February 28, 2005, the applicant identified two additional buildings brought into the LRA scope and the added LRA sections are as follows.

2.4.7.8 Radwaste Building

2.4.7.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.8, the applicant identified the structures and components of the radwaste building that are subject to an AMR for license renewal.

The radwaste building is a cellular box-type concrete structure extending approximately 20 feet below grade and 30 feet above grade and supported by steel H-piles driven to bedrock. This building houses services common to all three units. The radwaste building is comprised predominantly of thick walls and slabs, the dimensions of which are determined by shielding requirements. In a few instances, walls and slabs are determined by structural requirements. The roof system is a steel-framed structure with either bracket supports on concrete walls or steel columns supported by the concrete floor at an elevation of 580.0 feet.

In LRA Table 2.4.7.8, the applicant identified the following radwaste building component types that are within the scope of license renewal and subject to an AMR:

- masonry block
- metal roofing
- piles
- reinforced concrete beams, columns, walls, and slabs
- roof membrane
- structural steel beams, columns, plates, and trusses

2.4.7.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.8 and UFSAR Section 12.2.5 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.8 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-15, dated March 25, 2005, the staff stated that LRA Section 2.4.7.8 states that "The portions of the radwaste building that contain components requiring an AMR include the entire structure and the component supports discussed above." Therefore, the staff requested the applicant to confirm that all structural elements of the radwaste building are scoped and screened in Table 2.4.7.8. If not, the applicant was requested to list those elements of the radwaste building that are excluded from the table and discuss the basis for their exclusion including BFN's assessment of the II/I implication of the excluded elements upon their adjacent in-scope elements pursuant to 10 CFR 54.4 (a)(2).

In its response, by letter dated April 14, 2005, the applicant stated that all structural elements of the radwaste building are scoped and screened in LRA Table 2.4.7.8.

The staff found the above response to RAI 2.4-15 acceptable. Therefore, the staff's concern described in RAI 2.4-15 is resolved.

2.4.7.8.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the radwaste building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the radwaste building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.7.9 Service Building

2.4.7.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.7.9, the applicant identified the structures and components of the service building that are subject to an AMR for license renewal.

This structure consists of exterior concrete walls and footings with an interior structural steel frame supported by concrete footings and floor slabs. The building provides office and shop areas for various onsite organizations.

In LRA Table 2.4.7.9, the applicant identified the following service building component types that are within the scope of license renewal and subject to an AMR:

- masonry block
- metal roofing
- reinforced concrete beams, columns, walls, and slabs
- roof membrane
- structural steel beams, columns, plates, and trusses

2.4.7.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7.9 and UFSAR Section 12.2.6.2 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.7.9 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-16, dated March 25, 2005, the staff stated that LRA Section 2.4.7.9 seems to indicate that only a portion of the service building is scoped and screened in LRA Table 2.4.7.9. Since the LRA provides only a general description of the boundaries between the in-scope and out-of-scope structural elements of the service building, the staff requested the applicant to list those elements of the service building that are excluded from the table and discuss the basis for their exclusion including BFN's assessment of the II/I implication of the excluded elements upon their adjacent in-scope elements pursuant to 10 CFR 54.4 (a)(2).

In its response, by letter dated April 14, 2005, the applicant stated:

> During the scoping and screening of the Service Building for the newly identified mechanical systems discussed in the response to RAI 2.1-2A(3), only a limited area of the Service Building contained the new in-scope mechanical piping. Based on that fact, it was determined that the entire structure did not need to be within the scope of license renewal for the period of extended operation and this is described in the second paragraph of the response as noted on page E3-9 and reads as following; "The Service Building contains CO_2 piping and a liquid (water) filled piping for the fire protection system that are required to support fire protection requirements (10 CFR 50.48) based on the criterion of 10 CFR 54.4 (a)(3). Only those rooms of the Service Building that contain the fire protection piping are required to provide structural support and shelter/protection to support the intended function of the fire protection piping."
>
> In order to maintain the structural integrity of the structure within the scope of license renewal and provide reasonable assurance that these piping systems will be able to perform their intended functions, a portion of the structure was required to be in-scope such that the structure will perform its intended functions of "shelter/protection" and "structural support" of 10 CFR 54.4(a)(3) components. The in-scope boundary of the Service Building is described in the second paragraph on page E3-10 and reads as following; "In order to maintain the structural integrity of the Service Building to provide its intended functions for the in-scope components, the building area considered in-scope for the structure will be extended two column line bays in the west direction to column line S4 and will include the entire structure in the north-south direction between the personnel corridors on elevations 565.0' and 580.0' and roof at elevation 595.0' south of column line Sa to the north exterior wall of the Service Building. It should be noted that column line S7 is the east exterior wall of the Service Building and is located adjacent and parallel to the west exterior wall of the Unit 1 turbine building. Additionally, from the foundation slab at El 565.0' (top of floor slab EL 565.0') to the general roof deck of the structure at EL 595.0' and to EL 605.0' above the mechanical equipment room located between column lines S5 and S6 (west to east) and the Pull-Out Space & Shop Storage between column lines S6 and S7 (west to east) and between column lines Sb to approximately 6 ft north of column line Sh (south to north) defines the in-scope height of the structure." The basis for concluding that the structural integrity boundary of the in-scope structure will be maintained is based on a review of the design of the Service Building.

The structural elements of the Service Building that are listed in Table 2.4.7.9 encompass all the structural elements of the Service Building and none were excluded.

The staff found the above response to RAI 2.4-16 acceptable. Therefore, the staff's concern described in RAI 2.4-16 is resolved.

2.4.7.9.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI response described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the service building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the service building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.8 Structures and Component Supports Commodities

2.4.8.1 Structures and Component Supports Commodity Group

2.4.8.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.8.1, the applicant described the structures and component supports commodity group. This group includes specific types of structures and component support elements located in structures that are within the scope of license renewal. Physical interfaces exist with the structure, system or component being supported and with the building structural element to which the support is anchored. The supports located within a structure that are included within the scope of license renewal are identified under the individual structure's description. The in-scope items include support members, welds, bolted connections, anchorage (including base plate and grout) to the building structure, spring hangers, guides, and building concrete at bolt locations.

The component supports commodity group includes the following sub-groups: (1) supports for ASME piping and components (GALL Report Items III.B1); (2) supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing and non-ASME piping and components (GALL Report Items III.B2); (3) anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation (GALL Report Items III.B3); (4) supports for emergency diesel generator (EDG), HVAC system components, and miscellaneous mechanical equipment (GALL Report Items III.B4); and (5) supports for platforms, pipe whip restraints, jet impingement shields, masonry walls, and other miscellaneous structures (GALL Report Items III.B5). The first sub-group includes the supports and support anchorage for ASME-equivalent code class piping and components, or for the components that comprise the interface between the structure and the mechanical component. The second sub-group includes the supports and support anchorage for cable trays, conduits, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components that comprise the interface between the structure and the mechanical, electrical, or instrument component. The third sub-group includes the supports and support anchorage for enclosures of various types that contain and support electrical equipment. Components evaluated in this group comprise the interface between the structure and the electrical or instrument component. The fourth sub-group includes the supports and support anchorage for equipment not addressed in the previous groups that comprise the boundary between the structure and the component. Finally, the fifth sub-group includes structures and anchorage for miscellaneous structures as described above that indirectly support operation. These components comprise the evaluated structure and its anchorage.

A primary function of a support is to provide anchorage for the supported element for DBEs so that the supported element can perform its intended function or functions.

In LRA Table 2.4.8.1, the applicant identified the following structures and component supports commodity group items that are within the scope of license renewal and subject to an AMR:

- ASME-equivalent supports and components
- bolting and fasteners
- cable trays and supports
- conduit and supports
- duct banks and manholes
- electrical panels, racks, cabinets, and other enclosures
- equipment supports and foundations
- HVAC duct supports
- instrument line supports
- instrument racks, frames, panels, and enclosures
- non-ASME equivalent supports and components
- pipe whip restraints and jet impingement shields
- reinforced concrete beams, columns, walls, and slabs
- stairs, platforms, and grating supports
- trenches
- tube rack
- tunnels

2.4.8.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.8.1, UFSAR Section 5.2 and Appendix C using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the structural component functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted 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 had identified as being within the scope of license renewal to verify that the applicant had not omitted 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 2.4.8.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.4-13, dated December 20, 2004, the staff stated that the information provided in LRA Section 2.4.8.1 did not make it clear to the staff that all component supports within the scope of license renewal are included in the component supports commodity group. Therefore, the staff requested clarification for several components listed in LRA Table 2.4.8.1. The staff requested the applicant to provide the following:

a. Clarify whether the ASME equivalent supports and components listed in Table 2.4.8.1 include the reactor vessel support skirt/support ring and reactor vessel upper lateral stabilizer support. If not, the applicant was requested (1) to explain where these supports were addressed in the LRA, and (2) to submit the technical basis for crediting an alternate AMP for these supports, if they are not managed by ASME Section XI, Subsection IWF.

b. Clarify whether the ASME Equivalent Supports and Components of LRA Table 2.4.8.1 include the drywell lower ring support and the drywell upper lateral support. If the drywell supports are not managed by ASME Section XI, Subsection IWF, the applicant was requested to submit the AMR for them, including the technical basis for this exception.

c. Since LRA Section 2.4.8.1 is not referenced anywhere in LRA Sections 2.3 or 2.4, the applicant was requested to verify that all supports associated with components listed in LRA Sections 2.3 and 2.4.1 through 2.4.7 are included in the component types listed in LRA Table 2.4.8.1. If not, the applicant was requested to identify the supports not included and submit the AMR, including credited AMPs.

d. Confirm that the "Bolting and Fasteners" listed in LRA Table 2.4.8.1 includes anchors directly installed into concrete.

In its response, by letter dated January 24, 2005, the applicant stated:

> a. The reactor vessel support skirt, reactor vessel support ring girder and reactor vessel upper lateral stabilizer are included with “ASME Equivalent Supports and Components” component group as listed in LRA Table 2.4.8.1. See response to RAI 2.4-2 (f), RAI 2.4-2 (g) and 2.4-2 (a) for AMR results for these components respectfully.
>
> b. The ASME Equivalent Supports and Components of Table 2.4.8.1 do not include the drywell lower ring support and the drywell upper lateral support. Steel Containment Elements in Table 2.4.1.1 include the drywell lower ring support (drywell support skirt) and the drywell upper lateral supports. These components are classified as part of Class MC and BFN is not required to inspect MC supports in accordance with ASME Section XI. Refer to NRC RAIs B.2.1.33-1 and B.2.1.33-2 and TVA’s responses to those RAIs for justification of why they are not inspected to ASME Section XI, Subsection IWF. The drywell lower ring support is inaccessible (embedded in the Reactor Building concrete).
>
> c. LRA Section 2.4.8, “Structures and Component Supports Commodities,” includes all supports associated with the components listed in LRA Sections 2.3 and 2.4.1 through 2.4.7, with one exception:
>
> (1) LRA Table 2.3.1.2 of Section 2.3.1.2 identifies various components internal to the reactor vessel that provide support for other internal

components. Aging management of reactor vessel internals components is presented in LRA Table 3.1.2.2.

d. In LRA Table 2.4.8.1, the component group “Bolting and Fasteners” was included in error and should be deleted from the table. LRA Table 2.4.8.1 should read as shown below:

LRA Table 2.4.8.1 - Structures and Component Supports

Component Type	Intended Functions
ASME Equivalent Supports and Components	SS
Cable Trays and Supports	SS, and/or SS(NSR)
Conduit and Supports	SP, SS, and/or SS(NSR)
Duct Banks, Manholes	SS
Electrical Panels, Racks, Cabinets, and Other Enclosures	SP, SS, and/or SS(NSR)
Equipment Supports and Foundations	SS, and/or SS(NSR)
HVAC Duct Supports	SS, and/or SS(NSR)
Instrument Line Supports	SS, and/or SS(NSR)
Instrument Racks, Frames, Panels & Enclosures	SP, SS, and/or SS(NSR)
Non-ASME Equivalent Supports and Components	SS, and/or SS(NSR)
Pipe Whip Restraints and Jet Impingement Shields	PW and/or HE/ME
Reinforced Concrete Beams, Columns, Walls, and Slabs	SS, and/or SS(NSR)
Stairs, Platforms, Grating Supports	SS, and/or SS(NSR)
Trenches	SS(NSR)
Tube Track	SS, and/or SS(NSR)
Tunnels	SS, and/or SS(NSR)

Each of the component support commodity groups identified in LRA section 2.4.8.1 includes bolting and anchors, including anchors installed into concrete. This information has been provided in the discussion for the five Structures and Component Supports Commodity Groups in LRA Section 2.4.8, pages 2.4-55 and 2.4-56.

Item (b) of the above response refers to the applicant’s response to RAIs B.2.1.33-1 and B.2.1.33-2, and the applicant’s justification for why the drywell lower ring support and the drywell upper lateral support are not inspected to ASME Section XI, Subsection IWF. The staff evaluation covering the applicant’s response to RAIs B.2.1.33-1 and B.2.1.33-2 is provided in SER Section 3.0.3.2.21.

The staff found that the applicant response, above, fully addressed the concerns identified in RAI 2.4-13; therefore, the staff’s concern described in RAI 2.4-13 is resolved.

In RAI 2.4-14, dated December 20, 2004, the staff stated that based on information provided in LRA Section 2.4, the staff could not identify the insulation and insulation jacketing included within the scope of license renewal nor the specific subsets of insulation and insulation jacketing that are included in LRA Section 2.4 tables. It was also unclear whether insulation and jacketing on the reactor coolant system had been included; therefore, the staff requested the following of the applicant:

- Identify the structures and structural components designated as within the license renewal scope that have insulation and/or insulation jacketing, and identify their location in the plant.
- List all insulation and insulation jacketing materials associated with the item (a) above that require an AMR and the results of the AMR for each.
- For insulation and insulation jacketing materials associated with the item (a) above that do not require aging management, submit the technical basis for this conclusion, including plant-specific operating experience.
- For insulation and insulation jacketing materials associated with the item (a) above that require aging management, identify the AMP(s) credited to manage aging.

In its response, by letter dated January 24, 2005, the applicant stated:

> As stated in Section 2.1.7.2 of the Application, Insulation at BFN does not have an intended function within the scope of 10 CFR 54.4(a)(3).

In its response, by letter May 18, 2005, the applicant provided follow-up information to address the staff's concern that insulation was not in scope and subject to an AMR, as stated below:

> Thermal insulation is in scope and meets the criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3).
>
> The AMR results for insulation/insulation jacketing are provided in the new Section 3.0.2, shown in Attachment 2 to this response.

The staff found the above response to RAI 2.4-14 acceptable. Therefore, the staff's concern described above is resolved.

2.4.8.1.3 Conclusion

The staff reviewed the LRA, related structural components, and RAI responses described above to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the structures and component supports commodity group components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the structures and component supports commodity group components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.9 Conclusion

On the basis of its review, the staff concluded that the applicant had adequately identified the structures and components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the BFN structures and components that are 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 documents the staff's review of the applicant's scoping and screening results for electrical and I&C systems.

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived electrical and I&C SSCs 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 there were no omissions of electrical and I&C system components that meet the scoping criteria and are subject to an AMR.

Staff Evaluation Methodology. The staff's evaluation of the information provided in the LRA was performed in the same manner for all electrical and I&C systems. The objective of the review was to determine if the components and supporting structures for a specific electrical and I&C system that appeared to meet the scoping criteria specified in the Rule had been identified by the applicant 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 were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Scoping. To perform its evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing its review on components that had not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each electrical and I&C system component to determine if the applicant had 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 if all intended functions delineated under 10 CFR 54.4(a) had been specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

Screening. Once the staff completed its review of the scoping results, it evaluated the applicant's screening results. For those systems and components with intended functions, the staff sought to determine (1) if the functions are performed with moving parts or a change in configuration or properties, or (2) 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 did not meet either of these criteria, the staff sought to confirm that these electrical and I&C systems and components were subject to an AMR as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.5.1 Electrical and Instrumentation and Control Commodities

2.5.1.1 Summary of Technical Information in the Application

In LRA Section 2.5.1, the applicant described the electrical and I&C commodities. The electrical and I&C commodities have intended functions to power and control components that meet the requirements of 10 CFR 54.4. For this section, the applicant performed component-level scoping, evaluating by commodities rather than by system components.

The electrical and I&C commodities contain SR components that are relied on to remain functional during, and following, design-basis events. The failure of NSR SSCs in the electrical and I&C commodities could prevent the satisfactory accomplishment of an SR function. In addition, the electrical and I&C commodities perform functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- conducts electrical current
- provides electrical insulation
- provides structural support

In LRA Table 2.5.1, the applicant identified the following electrical and I&C commodities component types that are within the scope of license renewal and subject to an AMR:

- bus (with enclosures), transmission conductors, and high-voltage insulators (metallic portions)
- bus and high-voltage insulators (non-metallic portions)
- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements (connections include connectors, splices, terminal blocks, fuse blocks/clips, and electrical/I&C penetration assembly pigtails and connectors)
- various electrical equipment subject to 10 CFR 50.49 EQ requirements

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5.1 using the evaluation methodology described in SER Section 2.5. The scoping and screening of electrical and I&C components were performed using the spaces approach described in LRA Section 2.1. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.5, "Scoping and Screening Results - Electrical and Instrumentation and Controls Systems."

In the performance of the review, the staff reviewed the UFSAR for any functions delineated under 10 CFR 54.4(a) that had not been identified as intended functions in the LRA, to verify that the SSCs with such functions will be adequately managed to maintain the functions consistent with the CLB for the extended period of operation. The staff then reviewed the LRA to verify that passive or long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In LRA Section 2.5.1, the applicant said that the electrical commodities meet the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) and the related requirements for fire protection, EQ, ATWS, and SBO. During its review, the staff identified AMRs for components that are not explicitly addressed for Unit 1. These AMR items are those identified in the scoping and screening evaluation corresponding to LRA Appendices F3, F4, and F7, items shown with a bold-bordered enclosures in LRA Appendix F (see SER Sections 2.6.1.3, 2.6.1.4, and 2.6.1.7). In a letter dated October 8, 2004, the staff requested additional information required for the AMR with respect to these Unit 1 items.

In response to a generic RAI dated January 31, 2005, the applicant provided additional information concerning integration of Unit 1 Restart and License Renewal Activities, which states

> The license renewal application was structured to reflect the configuration and current licensing basis of all three units. Scoping and screening as well as aging management reviews were done based on the current licensing bases and configuration of all three units. The differences between the units that are relevant to the application and will be resolved prior to Unit 1 restart, are listed in Appendix F. As each activity identified in Appendix F is completed, the corresponding highlighted (bolded bordered) text in the license renewal application will apply to Unit 1. The only change to the application will be to remove the bolded border. No changes are required to scoping and screening results, aging management review results, or TLAAs. In some cases, boundary drawings would change to reflect the bolded bordered text.

The staff reviewed the applicant's response for these items and accepts the methodology as proposed by the applicant for these bold-bordered items throughout the LRA. These modifications are currently not physically implemented for Unit 1 to match Units 2 and 3 CLB. However, the applicant stated in its response that the scoping and screening as well as the AMRs are done forward-looking for these bold-bordered enclosure items, based on the CLB for Units 2 and 3, which will also apply to Unit 1 when the modifications are completed. As each activity identified in Appendix F is completed, the corresponding bold-bordered text in the LRA will apply to Unit 1. The applicant commits to update the status of this implementation in a future submittal and through the annual LRA update to the CLB, the next one in January 2006. This commitment will be tracked through a temporary instruction (TI)-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. The applicant also committed to inform the staff as these activities are completed and to reflect the status in annual and other periodic updates. Based on the above, the staff finds this issue for the electrical and I&C resolved.

In reviewing LRA Section 2.5, the staff identified areas in which additional information was necessary to com

plete the evaluation of the applicant's scoping and screening results. Therefore, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following discussion describes the staff's RAIs and the applicant's related responses.

In RAI 2.5-1, dated November 1, 2004, the staff stated that in LRA Section 2.5-1, the applicant stated that scoping and screening of electrical and I&C components was performed using the spaces approach described in LRA Section 2.1. Therefore, the staff requested the applicant to specify if all plant spaces had been evaluated using this methodology. If any spaces had been excluded from this evaluation, the staff asked the applicant to identify the excluded spaces and to explain why the spaces were excluded.

In its response, by letter December 1, 2004, the applicant stated:

> The "spaces" approach was used for scoping and screening of all plant spaces. The only time the "spaces" approach was not utilized was scoping and screening of the SBO

> recovery path. The “intended function” approach was utilized to identify which specific components were required for SBO recovery.

The staff found this response acceptable; therefore, the staff’s concern described in RAI 2.5-1 is resolved.

In RAI 2.5-2, dated November 1, 2004, the staff noted that in LRA Section 2.1.5.2 the applicant had stated that if a component in a commodity group existed in an area where the area conditions exceeded the commodity group’s limiting environmental parameters, a further evaluation could be performed to determine if the component was required for an intended function of a system within the scope of license renewal. Therefore, the staff requested the applicant to identify all the components that were excluded from the scope of license renewal as a result of these further evaluations and to provide the basis used for excluding each component.

By letter of December 1, 2004, the applicant responded as follows:

> The following cables or cable types were scoped in by the “spaces” approach but screened out of the scope of license renewal using further evaluations:
>
>> Cable Type THHN is PVC [polyvinyl chloride] insulated lighting wire - THHN lighting wire was used in one circuit in the Drywell for normal lighting. This circuit is not required for Appendix R or SBO lighting and was screened out of the scope of license renewal.
>>
>> Cable Type TW is a PVC insulated ground wire - BFN uses an ungrounded electrical system thus equipment grounds are for personnel protection only and degradation of the PVC insulation would not adversely affect equipment operation.
>>
>> The Safe Shutdown Analysis does not list any safety-related intended functions for Source Range Monitors (SRMs) and Intermediate Range Monitors (IRMs) Nuclear Instrumentation. Therefore, the Source Range and the Intermediate Range Nuclear Instrumentation circuitry are screened out and are not subject to an AMR.
>>
>> The Safe Shutdown Analysis does not list any safety-related functions associated with the Rod Block Monitors (RBMs). Therefore, the RBM circuitry is screened out and is not subject to an AMR.
>>
>> The only safety-related functions listed in the Safe Shutdown Analysis for the Traversing Incore Probe system (TIP) is provide a reactor coolant pressure boundary. Therefore, TIP circuitry is screened out and is not subject to an AMR.
>>
>> The following inaccessible medium-voltage cables located in underground conduit duct banks were screened out and not subject to an AMR since they do not perform an intended function for license renewal as specified by 10 CFR 54.4.

- Cables routed to Off-gas Treatment Building Transformers A & B
- Cables routed from the Condensate Circulating Water Pumps to the Condensate Circulating Water Pump (CCWP) capacitor banks
- Cables routed to Cooling Tower equipment

The staff found the exclusions and the reasons for the exclusions from the scope of license renewal acceptable for all the components except the source range monitor (SRM) and intermediate range monitor (IRM) cables, and the cables routed to off-gas treatment building transformers A and B. In an email dated December 15, 2004, the staff asked the applicant for a further response to RAI 2.5-2, clarifying why these components had been excluded from the scope of license renewal.

The staff contended that nuclear instrumentation circuits cannot be screened out since these circuits perform a safety function and provide trip signals to prevent any fuel damage during low power operations. The staff, in support of this item, cited the applicant's statement in LRA Section 2.3.3.32: "The Neutron Monitoring System detects conditions that could lead to local fuel damage and provides signals that can be used to prevent such damage."

With regard to the SRM circuit cables, the staff concurred with the applicant that, because the SRM circuit cables are not designated as SR and they are not in the technical specification for BFN, they do not require an AMR.

With regard to the IRM nuclear instrumentation circuitry, the applicant agreed with the staff that IRM instrumentation circuit cables should be within the scope of license renewal because they are part of the BFN technical specification. Because of this inclusion, the applicant confirmed that their aging effects should be managed by the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. All other accessible neutron monitoring subsystem cables and connections will be managed by the Accessible Non-Environmental Qualification Cables and Connections Inspection Program. This inclusion impacts the scope of the AMP's elements "Program Description" and "NUREG-1801 Consistency." These changes have been added to the SER Appendix A commitment table, and the applicant will modify the UFSAR supplement to reflect these changes.

With regard to the exclusion of cables routed to off-gas treatment building transformers A and B because they did not serve any intended function, the staff identified technical information in LRA Section 2.3.3.19 that stated that the off-gas system is within the scope of license renewal in accordance with 10 CFR 54.4(a). The SR functions of the off-gas system are to provide flow path integrity for the release of the filtered standby gas treatment system gases to the stack, and to provide automatic closure of back-draft prevention dampers to prevent back flow and potential ground-level release of radiation. Therefore, the staff contended that cables routed to off-gas treatment building transformers A & B cannot be screened out.

In its response dated January 18, 2005, the applicant stated that in performing SR functions the off-gas system relies solely on mechanical components that do not require electrical power. Therefore, the applicant stated that medium-voltage cables routed to off-gas treatment building transformers A and B are screened out and not subject to an AMR.

The staff concurred with the applicant’s response dated January 18, 2005, that the intended functions of the off-gas system addressed in LRA Section 2.3.3.19 are accomplished through mechanical means without electrical power. However, the fans of the standby gas treatment system listed in LRA Section 2.3.2.2 are within the scope of license renewal and are powered by these transformers. Therefore, the cables listed in LRA Section 2.3.2.2 as being in the standby gas treatment system should be within the scope of license renewal.

Based on the above, the staff identified additional follow-up to RAI 2.5-2. In an informal request on January 31, 2005, the staff requested clarifications on why these medium-voltage cables to off-gas treatment building transformers A and B had been screened out.

In its response to clarifications to follow up to RAI 2.5-2, by letter dated March 2, 2005, the applicant stated that standby gas treatment blowers, which are within the scope for license renewal, are not powered from off-gas treatment building transformer A and B. The applicant stated that the standby gas treatment system and the off-gas treatment system are completely different systems, independent of each other and located in different buildings that do not share power distribution systems or equipment. Standby gas treatment blowers, which are in scope for license renewal, are not powered from off-gas treatment building transformers A and B. In its response dated March 2, 2005, the applicant also provided details of the electrical circuits that support its contention that these blowers are not powered from the above transformers. The staff was satisfied with the explanation and considers this issue resolved.

On the basis of its review, the staff found that the applicant had adequately addressed all of the staff's concerns raised in RAI 2.5-2. Therefore, the staff’s concerns described in RAI 2.5-2 are resolved.

In RAI 2.5-3, dated November 1, 2004, the staff requested additional information regarding the three license renewal drawings identified in LRA Section 2.5.1 that depict the recovery path for SBO and identify the location of each commodity group component in the recovery path circuit.

In its response, by letter December 1, 2004, the applicant properly identified the location of each commodity group component in the SBO recovery path. The response includes details from the 500 kV switchyard to the 4kV shutdown boards for all three units, transmission conductor runs between breakers, and isolated phase bus runs between the main transformers and the unit station service transformers. The applicant also stated that the SBO recovery path circuits include control circuit wiring. The low-voltage power and control circuit wiring associated with the power circuit breakers and disconnects are included within the scope of license renewal, and there are no 500kV, 161kV, or 4kV underground power circuits used in SBO recovery paths. These details are documented in its response.

The staff found these details were in order and on the basis of its review, the staff found the applicant’s response acceptable. Therefore, the staff’s concern described in RAI 2.5-3 is resolved.

In RAI 2.5-4, dated November 1, 2004, the staff stated that during a teleconference held on July 28, 2004, in response to a request for additional information, RAI 3.6-3, the applicant stated that in 1997 a cross-linked polyethylene (XLPE)-insulated CCWP capacitor bank cable failed in-service at BFN. Therefore, the staff requested that the applicant explain why these cables were not included within the scope of license renewal and identified as a component that requires an AMR.

In its response to RAI 2.5-4, the applicant stated that the condensate circulating water (CCW) system (system 027) is within the scope of license renewal because it provides manual vacuum breaking capability to prevent backflow from the cooling tower warm channel into the forebay upon trip of the CCW pumps. The capacitor bank provides additional starting power for the condenser circulating water pumps to minimize loading on the electrical distribution system. But, as previously stated in the response to RAI 2.5-2, above, the CCWP capacitor bank cables are medium-voltage cables that do not perform an intended function for license renewal as specified in 10 CFR 54.4. The staff had previously accepted the applicant's position that these cables are screened out and not subject to an AMR.

On the basis of its review, the staff found that the applicant had adequately addressed the staff's concern. Therefore, the staff's concern described in RAI 2.5-4 is resolved.

2.5.1.3 Conclusion

During its review of the information provided in the LRA, RAI responses, and the UFSAR, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for electrical and I&C commodities. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that the applicant had adequately identified the electrical and I&C commodities components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the electrical and I&C commodities components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6 Integration of Browns Ferry Nuclear, Unit 1, Restart Activities and License Renewal Activities

BFN was designed and constructed by the applicant and licensed in 1973, 1974, and 1976 respectively. The three units are identical GE BWR/4 reactors with Mark I containments. The units operated from original licensing until 1985 when they were voluntarily shut down by the applicant to address management and technical issues. The applicant then implemented a comprehensive nuclear performance plan to correct the deficiencies that led to the shutdown. This plan included changes in management, programs, processes, and procedures, as well as extensive equipment refurbishment, replacement, and modifications. Unit 2 was subsequently restarted in 1991, and Unit 3 followed in 1995. In the early 1990s, the applicant decided to defer restart of Unit 1. On May 16, 2002, the applicant announced the Unit 1 restart project. The applicant had previously notified the staff of its intent to submit an LRA for Units 2 and 3 by December 31, 2003. The applicant met with the staff on July 24, 2002, to discuss its proposal to submit the LRA for all three units. Subsequent meetings were held with the staff on October 31, 2002, April 23, 2003, and September 29, 2003. Meeting summaries are documented by letters dated November 25, 2002, June 2, 2003, and October 30, 2003, respectively, regarding the license renewal application. In those meetings, agreement was reached with the staff on the content and format of the application to ensure that it met all regulatory requirements and supported staff review.

License Renewal Application Content. In the meetings referenced above, the applicant explained that, although it was engaging in numerous plant modifications and restart activities, the CLB for Unit 1 was well-known, defined, and documented, and the LRA would be prepared based on the CLB. The unique element with Unit 1 is that restart activities include modifying the Unit 1 licensing basis to make it consistent with the CLB of Units 2 and 3. During the meetings with the staff, it was agreed the applicant would identify in the LRA the Unit 1 differences that will be eliminated when restart activities are completed. To highlight these differences, information not yet applicable to Unit 1 was marked with a bolded border. This annotation methodology is consistent with previous multi-plant LRAs submitted to the staff. LRA Appendix F describes each of these differences, its effect on the application, and the schedule for resolution. It also provides references to application sections affected. This enabled the applicant to submit an LRA based on the CLB for all three units, as well as to identify Unit 1 restart activities relevant to the LRA. As previously stated, the BFN units are essentially identical, and the application is not unit-specific with regard to AMPs. The changes being implemented as part of Unit 1 restart activities are consistent with the changes made previously to Units 2 and 3. The AMPs are common for all three units because at restart the Unit 1 licensing basis will be the same as the licensing basis for Units 2 and 3.

2.6.1 Regulatory Framework for Review of BFN LRA and Integration Unit 1 Restart Activities

By letter dated December 31, 2003, the applicant submitted an application pursuant to 10 CFR 54 to renew the operating licenses for the BFN Units 1, 2, and 3. The applicant is submitting additional information concerning the status of Unit 1 restart activities and the impact of those activities on the LRA. LRA Appendix F states that the Unit 1 restart program will result in three operationally identical BFN units, providing assurance that the Unit 1 CLB changes implemented prior to restart will result in the same CLB as that of Units 2 and 3 and that, therefore, the AMPs for each unit are the same. The Unit 1 CLB differences described in LRA Appendix F will be resolved prior to Unit 1 restart.

BFN has a single UFSAR common to all three units. Unit 1 has been maintained in essentially the same physical configuration as it was when it was shut down in 1985 (except for systems required to keep Unit 1 in the shutdown condition or to support Units 2 and 3 operation). As required by 10 CFR 50.71, the UFSAR was updated for all three units when amendments were issued common to all the units. In 1998, the Unit 1 Technical Specifications were converted to Improved Technical Specifications, as they were for Units 2 and 3. The license renewal UFSAR supplement Appendix A identifies and describes the AMPs that are required for all three units. No AMPs unique to Unit 1 are required during the period of extended operation. However, for portions of Unit 1 systems that have not been replaced, the staff concluded that there was insufficient operating history or data to conclude that one-time inspections are appropriate substitutes for periodic inspections. Based on the advice from the interim review by the ACRS in its 526th subcommittee meeting and in resolving the staff concerns in this matter, AMP B.2.1.42, "Unit 1 Periodic Inspection Program," was added to supplement one-time inspections. The committee also felt that periodic inspections are the most significant compensating actions for the lack of plant-specific operating experience of BFN Unit 1. This new AMP is only applicable to Unit 1 and was added as a result of the staff reaching an agreement with the applicant for managing piping and components left in place, specifically, the ones subjected to the layup program.

The LRA was structured to reflect the configuration and CLB of all three units. Scoping and screening as well as AMRs were done based on the configuration and CLB of all three units. The differences between the units that are relevant to the application, and which will be resolved prior to Unit 1 restart, are listed in LRA Appendix F.

As each activity identified in LRA Appendix F is completed, the corresponding highlighted (bold-bordered) text in the LRA will apply to Unit 1. The only change to the application will be to remove the bolded border. No changes are required to scoping and screening results, AMR results, or TLAAs. In some cases, boundary drawings would change to reflect the bold-bordered text. Accordingly, the staff reviewed all the bold-bordered items in the LRA as they will exist when Unit 1 restarts. The staff review of Unit 1 items focused on the material, aging effect, and AMPs as they exist in Units 2 and 3. There was no unique impact of these evaluations on Unit 1 items, because the applicant stated that there were no unique AMPs for Unit 1. The BFN procedures for AMPs apply site-wide and BFN procedures for new AMPs and AMP enhancements will be issued for all three units.

LRA Appendix F provides the applicant's plans and the schedules for Unit 1 restart activities affecting the LRA. Whenever text shown with a bold-bordered box appears in the LRA, indicating a licensing or design basis that only applies to Units 2 and 3, a link is provided to the appropriate LRA Appendix F section.

LRA Appendix F summarizes the resolution of the differences between Unit 1 and Units 2 and 3. For each difference, the following information is presented:

<u>Description</u> – Describes the difference.

Difference Resolution – Explains the methodologies and activities that the applicant plans to use to disposition each licensing or design-basis difference.

LRA Impact – Summarizes changes that would be expected to the LRA, if the condition were resolved prior to issuance of the renewed licenses.

Schedule for Completion – Relates to milestones rather than specific dates. The schedules reflect the current schedules in the Unit 1 restart plan and are subject to change as the plan is implemented. The following milestones have been defined:

- Prior to renewed license issuance – The applicant expects the resolution activities to be complete prior to the expected issuance date of the renewed licenses.
- Prior to restart – The applicant will complete the resolution activities prior to Unit 1 restart.
- Permanent – The difference is acceptable as-is for license renewal. No changes related to license renewal are necessary or planned for the condition.
- If a submittal is required, the submittal milestone is stated.
- Systems/structures/components impacted – The impacted systems, structures, or components are identified with links to the appropriate sections in LRA Chapter 2 sections and the appropriate LRA Chapter 3 sections.
- AMPs/TLAAs Impacted – The impacted AMPs and TLAAs are identified with links to the appropriate section in LRA Chapter 4 and Appendix B.

Staff Evaluation Methodology. In reviewing the technical information provided in LRA Appendix F, and January 31, 2005, letter, the staff review was limited to verifying (1) the sufficiency of information provided by the applicant for the 13 items that impacted the LRA review, (2) the applicability of the 13 items to Unit 1, (3) the systems these 13 items impacted, and (4) the plan to resolve differences between the CLB for Unit 1 and the CLB for Units 2 and 3, so that upon restart all units will have the same CLB. It should be noted that in the LRA the restart activities listed in LRA Appendix F are generally referred to as differences in the design basis or licensing basis. Based on the definition of CLB in 10 CFR 54.3, these activities are more precisely described as implementation activities of the design and licensing basis. The applicant, by submittal dated March 2, 2006, provided details of previous safety evaluations completed under 10 CFR 50.59, under plant changes that do not require staff approval and agreed to make these evaluations available for an audit if necessary. Even though each of the 13 activities listed in LRA Appendix F is committed to and planned for completion prior to Unit 1 restart, any unimplemented commitments would remain valid, part of the CLB, carry over into the renewed license period, and be controlled by the NRC regulatory and oversight process.

The staff's evaluation of the information provided in the LRA was performed in the same manner for all mechanical, civil, electrical systems as it relates to the particular item in question. The objective of the review was to determine if the components and supporting structures for a specific mechanical system that appeared to meet the scoping criteria specified in the Rule had been identified by the applicant as being within the scope of license renewal. 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).

Specific planned Unit 1 restart activities that impact license renewal are provided below.

2.6.1.1 Main Steam Isolation Valve Alternate Leakage Treatment

Description. In LRA Section F.1 the applicant described the proposed modification. The Unit 1 CLB for MSIV leakage does not incorporate an alternate leakage treatment pathway utilizing main steam system piping and main condenser. The Unit 1 main steam piping from the outermost isolation valve up to the turbine stop valve, the bypass/drain piping to the main condenser, and the main condenser is being evaluated and will be modified as required to ensure structural integrity is retained during and following an SSE. This will allow use of methodology that assumes plateout and holdup in the piping and condenser (in LOCA offsite and control room dose calculations) for radioactive leakage past the MSIVs. In the LRA, the applicant stated that this methodology was included in the Units 2 and 3 CLB and will be incorporated prior to Unit 1 restart.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by approval of a technical specification change dated July 9, 2004, and implementation of the actions committed to in the proposed change prior to Unit 1 restart. The applicant committed to revise plant operating procedures to provide procedural requirements to establish the alternate leakage treatment path to the condenser and to resolve the outliers identified in the supporting analysis.

LRA Impact. The Unit 1 systems and structures impacted by this modification and their LRA sections and tables:

- high pressure coolant injection (Section 2.3.2.3)
- auxiliary boiler (Section 2.3.3.1)
- sampling and water quality (Section 2.3.3.14)
- reactor core isolation cooling (Section 2.3.3.23)
- main steam (Section 2.3.4.1 and Table 3.4.2.1)
- condensate and demineralized water (Section 2.3.4.2 and Table 3.4.2.2)
- heater drains and vents (Sections 2.3.4.4 and 3.4.2.1.4 and Table 3.4.2.4)
- turbine drains and miscellaneous piping (Sections 2.3.4.5 and 3.4.2.1.5 and Table 3.4.2.5)
- turbine buildings (Section 2.4.7.1)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and currently forecasted to be completed by August 2006. Should the applicant not receive approval of technical specification (TS)-436, the effect on the license renewal is that the Unit 1 components credited in the MSIV alternate leakage pathway will not be within the scope of license renewal as currently planned. The Unit 1 boundary drawings will remain accurate and the increased scope identified by the bold-bordered boxes in the application will not be applicable. Staff reviews of the application would not change.

Staff Evaluation. The applicant evaluated the impacts to the scoping and screening of the affected SSCs because of this Unit 1 restart modification. The applicant stated that after approval of the proposed change (TS-436) and implementation of the actions committed to in the proposed change prior to Unit 1 restart, there will be no functional differences in the alternate leakage treatment pathways between Units 1, 2, and 3. The Unit 1 components that comprise the alternate leakage treatment pathway will be incorporated into the appropriate AMPs specified in the LRA, and there will be no unit-specific differences. The staff also concurred with the applicant’s evaluation that there are no changes to the previously evaluated intended function of respective systems and components screened and scoped previously.

In addition, Unit 1 modifications impact LRA Section 2.1 “Scoping and Screening Methodology,” which relates to the leakage pathway MSIV’s structural integrity. In its response dated May 31, 2005, the applicant provided information related to RAI 2.1-2A(1) and (2) concerning NSR components that affect SR piping regarding the secondary containment integrity and also related to RAIs 2.3.4.4-1 and 2.3.4.4-2. The staff found the applicant’s response to RAI 2.1-2A(1) and (2) acceptable; therefore, RAIs 2.3.4.4-1 and 2.3.4.4-2 are closed.

In its submittal dated January 31, 2005, the applicant forecasted that this modification will be completed by August 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment be will completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

Conclusion. During its review of the information provided in the LRA, license renewal drawings, RAI responses, and licensing-basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the structures and components because of the MSIV alternate leakage treatment modification. The scoping and screening reviews were done based on the CLB. The differences between the units’ CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated in SER Section 2.1.3.1.2, and the staff requested additional information. RAIs 2.1-2A(1) and (2) are related to seismic qualification of secondary containment penetration seals. The MSIV alternate treatment modification potential involves one such penetration. The staff in reviewing the structures and components impacted by these modifications concluded that the applicant had adequately identified Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21 (a)(1).

2.6.1.2 Containment Atmosphere Dilution System

Description. The CAD system consists of six pneumatic valves per unit, each with its own accumulator and check valve. The CAD system was originally designated for short-term use after DBEs. Long-term use (up to 100 days) was not considered in the original design. A request to consider the long-term use of the CAD system was included in NUREG 0737 (TMI action Plan), Item II.K.3.28 (Qualification of CAD Accumulators). The safety evaluation that documents the acceptability of the applicant's plan to satisfy Item II.K.3.28 for all three units was provided previously by letter dated July 24, 1985.

The CAD system must have the capability to supply pressurized nitrogen to operate the main steam relief valves when control air is not available to ensure the safe shutdown requirements of 10 CFR Part 50, Appendix R following fires, and 10 CFR 50.63 during an SBO. That capability has been installed on Units 2 and 3 and will be installed on Unit 1.

Difference Resolution. The differences between Unit 1 versus Units 2 and 3 will be resolved prior to Unit 1 restart by upgrading the Unit 1 CAD accumulator system and implementing its CLB, letter to NRC dated July 12, 1984. The capability to supply pressurized nitrogen to operate the main steam relief valves for the long-term when control air is not available will be provided by splitting the ring header into two sections and providing an alternate nitrogen supply to the drywell control air system.

LRA Impact. The Unit 1 systems and structures impacted by this modification and their LRA sections:

- containment (2.3.2.1)
- containment atmosphere dilution (2.3.2.7)
- control air (2.3.3.10)
- sampling and water quality (2.3.3.14)
- reactor building closed cooling water (2.3.3.22)
- radioactive waste treatment (2.3.3.25)
- feedwater (2.3.4.3)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and currently forecasted to be completed by July 2006. Should the applicant not make the modifications discussed above, the associated additional components planned to be installed would not be installed and, therefore, the additional components would not be within the scope of license renewal as currently planned. The Unit 1 boundary drawings would remain accurate and the increased scope identified by the bold-bordered boxes in the application would not be applicable. Staff reviews of the application would not change.

Staff Evaluation. Once the Unit 1 modifications are completed there will be no functional differences in the containment atmosphere dilution nitrogen supply between Units 1, 2, and 3. The Unit 1 components that comprise the containment atmosphere dilution nitrogen supply will be incorporated into the appropriate AMPs specified in the LRA, and there will be no unit-specific differences. As stated above, this modification is forecasted to be completed by July 2006, and it will be duly tracked by a separate LRA Appendix A commitment and LRA inspection prior to Unit 1 restart to confirm implementation.

In its submittal dated January 31, 2005, the applicant forecasted that this modification will be completed by August 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the containment atmosphere dilution system modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.3 Fire Protection

Description. The applicant is required by 10 CFR Part 50, Appendix R to have the capability to maintain safe shutdown during and after a fire at BFN station. The staff issued an SER, dated December 8, 1988, for the 10 CFR Part 50, Appendix R-Fire Protection Program, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Appendix R Safe Shutdown System Analysis," and supplemental safety evaluation, dated November 3, 1989, on the subject. In addition, by letter dated March 6, 1991, the staff issued an associated license amendment. The SER for the fire protection plan and fire hazards analysis was provided by staff letter to TVA, "Fire Protection Program - Browns Ferry Nuclear Plant Units 1, 2, and 3," dated March 31, 1993. The applicant's Fire Protection Report, Volume 1 (UFSAR Chapter 10.11), states that the 10 CFR Part 50, Appendix R requirements for operating units have been established and implemented for Units 2 and 3. The staff has also issued a license amendment for the 10 CFR Part 50, Appendix R post-fire safe shutdown program, dated November 2, 1995.

Difference Resolution. The differences between the current fire protection licensing basis for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by implementation of the Fire Protection Program on Unit 1.

LRA Impact. The Unit 1 systems, structures, and AMPs impacted by this modification and their LRA sections:

- reactor recirculation (2.3.1.4)
- containment (2.3.2.1)
- high pressure coolant injection (2.3.2.3)
- residual heat removal (2.3.2.4)
- containment atmosphere dilution (2.3.2.7)
- residual heat removal service water (2.3.3.3)
- high pressure fire protection (2.3.3.6)
- control air (2.3.3.10)
- sampling and water quality (2.3.3.14)
- emergency equipment cooling water (2.3.3.20)
- reactor water cleanup (2.3.3.21)
- reactor building closed cooling water (2.3.3.22)
- reactor core isolation cooling (2.3.3.23)
- radioactive waste treatment (2.3.3.25)

- fuel pool cooling and cleanup (2.3.3.26)
- control rod drive (2.3.3.29)
- main steam (2.3.4.1)
- condensate and demineralized water (2.3.4.2)
- feedwater (2.3.4.3)
- primary containment structure (2.4.1.1)
- reactor buildings (2.4.2.1)
- turbine buildings (2.4.7.1)
- electrical and instrumentation and control commodities (2.5.1)
- Fire Protection Program (B.2.1.23)
- Fire Water System Program (B.2.1.24)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

It is reasonable to assume that the Fire Protection Program will be implemented prior to Unit 1 restart.

Schedule for Completion. The Unit 1 analyses and modifications are scheduled for completion prior to restart and currently forecasted to be completed by August 2006.

Staff Evaluation. Once the Unit 1 Fire Protection Program modifications are completed there will be no functional differences between Units 1, 2, and 3. The Unit 1 components that comprise the high pressure fire protection system will be incorporated into the appropriate AMPs specified in the LRA and there will be no unit-specific differences. The staff review of Unit 1 items focused on the material, aging effects, and AMPs as they exist in Units 2 and 3, and there were no impacts of the evaluations on Unit 1 items, because the applicant stated that there was no unique AMP for Unit 1. The staff found the explanation acceptable.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by August 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the fire protection modification. The scoping and screening reviews were done based on the CLB. The differences between the units’ CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.4 Environmental Qualification

Description. A site-wide EQ Program required by 10 CFR 50.49 has been developed for BFN, and implemented on Units 2 and 3, and it is expected to be implemented on Unit 1 to ensure compliance with 10 CFR 50.49.

As part of the recovery program for Browns Ferry, by October 24, 1988 letter, the applicant committed to implement its EQ Program so that electrical equipment located in a harsh environment would meet 10 CFR 50.49 requirements prior to the restart of each unit. The safety evaluation for the program was issued by the staff on January 23, 1991. The site-wide EQ Program required by 10 CFR 50.49 was developed for BFN, implemented on Units 2 and 3, and is being implemented on Unit 1. This program defines responsibilities and specifies requirements to establish and maintain auditable documentation demonstrating the environmental qualification of equipment. This program is described in LRA Section 4.4.

The EQ Program:

- Identifies the applicable DBAs and determines the environmental parameters for those accidents. The environmental parameters are necessary for procurement, design, and qualification of equipment in accordance with 10 CFR 50.49.
- Identifies the equipment and cables in the harsh zones within the scope of 10 CFR 50.49 and determines their required operating times.
- Is established or procured and documented for each piece of equipment in the 10 CFR 50.49 list. Environmental Qualification Data Packages provide documented evidence that demonstrates the qualification of each piece of equipment for its specific application and environment. Components subject to 10 CFR 50.49 requirements that are not qualified for the license term must be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in their evaluation.
- Actions are identified, proceduralized, and initiated to maintain the qualification of installed equipment and cables. This includes periodic, preventive, or corrective maintenance; procurement controls; and storage requirements. The safety evaluation for the program was issued by the staff on January 23, 1991.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by implementation of the EQ Program on Unit 1, as stated in the LRA Sections 4.4 and B.3.1.

UFSAR Impact. The Unit 1 systems, structures, commodities, AMPs, and TLAAs impacted by this modification and its LRA sections and tables:

- reactor recirculation (Section 2.3.1.4)
- containment (Section 2.3.2.1)
- high pressure coolant injection (Section 2.3.2.3)
- residual heat removal (Section 2.3.2.4)
- core spray (Section 2.3.2.5)
- containment inerting (Section 2.3.2.6)

- containment atmosphere dilution (Section 2.3.2.7)
- control air (Section 2.3.3.10)
- sampling and water quality (Section 2.3.3.14)
- emergency equipment cooling water (Section 2.3.3.20)
- reactor water cleanup (Section 2.3.3.21)
- reactor building closed cooling water (Section 2.3.3.22)
- reactor core isolation cooling (Section 2.3.3.23)
- radioactive waste treatment (Section 2.3.3.25)
- control rod drive (Section 2.3.3.29)
- radiation monitoring (Section 2.3.3.31)
- main steam (Section 2.3.4.1)
- feedwater (Section 2.3.4.3)
- primary containment structure (Section 2.4.1.1)
- reactor buildings (Section 2.4.2.1)
- electrical and I&C commodities (Section 2.5.1 and Tables 3.6.1 and 3.6.2.1)
- EQ TLAA (Section 4.4)
- EQ Program (Section B.3.1)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 analyses and modification is scheduled for completion prior to restart and currently forcasted to be completed by July 2006.

Staff Evaluation. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by implementation of the EQ Program. Once the Unit 1 portion of the EQ Program is completed, the BFN site-wide EQ Program will ensure that the components subject to 10 CFR 50.49 requirements are maintained within the bounds of their qualification bases for the period of extended operation.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by August 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the EQ modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.5 Intergranular Stress Corrosion Cracking

The applicant submitted and implemented plans for addressing intergranular stainless steel stress corrosion cracking in accordance with generic letter (GL) 88-01 and Supplement 1 for Units 2 and 3. In accordance with the Unit 1 restart plan, GL 88-01 will be addressed for Unit 1.

Description. The BWR Stress Corrosion Cracking Program manages IGSCC in reactor coolant pressure boundary components made of stainless steel.

The applicant's program to address GL 88-01, the staff position on IGSCC in BWR austenitic stainless steel piping, for Unit 3 was provided by letter dated December 28, 1992. The applicant, by its letter dated August 1, 1988, previously committed to submit a report containing the details of the repair or replacement work. The safety evaluation documenting the acceptability of the program was provided and supplemental information regarding Unit 1 was submitted by letter dated December 3, 1993. The following wrought austenitic stainless steel piping systems and components on Unit 1 are considered susceptible to IGSCC according to the guidelines given in GL 88-01:

- reactor recirculation from the recirculation inlet and outlet nozzles to the connections with RHR
- RHR from the recirculation system to the first isolation valve outside of the drywell penetration
- reactor water cleanup (RWCU) from its connection to the RHR system to first isolation valve outside of the drywell penetration
- core spray from the core spray inlet nozzles to the drywell penetration, including the core spray inlet safe ends
- jet pump instrument safe ends

In its letter, dated July 21, 2004, the applicant informed the staff that the IGSCC-susceptible piping on Unit 1 is being replaced using materials that are resistant to IGSCC. To address the requirements for inspection schedules and expansion plans, the susceptible weldments have been categorized according to NUREG 0313, Revision 2, Section 5, Table 1. The in-service inspections are required by BFN Technical Requirements Manual, Section 3.4.3.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved Unit 1 prior to restart by the replacement of the IGSCC-susceptible piping, and by providing IGSCC protection or mitigation.

UFSAR Impact. The Unit 1 systems and AMPs impacted by this modification and their LRA sections and table:

- reactor vessel (Section 2.3.1.1)
- reactor recirculation (Section 2.3.1.4)
- residual heat removal (Section 2.3.2.4)
- core spray (Section 2.3.2.5 and Table 3.2.2.5)
- reactor water cleanup (Section 2.3.3.21)

- Boiling Water Reactor Stress Corrosion Cracking Program (B.2.1.10)
- BWR Reactor Water Cleanup System Program (B.2.1.22)

It is reasonable to assume that replacement of the IGSCC-susceptible piping will be performed. The applicant has already removed the original piping and must replace it to operate the unit. Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. Submittal of the Unit 1 IGSCC plan and implementation report, as well as the physical modification, are scheduled for completion prior to restart and currently forcasted to be completed by March 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not allow the applicant to enter the period of extended operation without implementing this modification.

Staff Evaluation. Once the piping replacement modifications are completed on Unit 1 there will be no functional differences in the IGSCC mitigation or protection between Units 1, 2, and 3. The Unit 1 components that mitigate IGSCC will be incorporated into the appropriate AMPs and there will be no unit-specific differences.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by August 2006. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the IGSCC modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff has not identified any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.6 Boiling Water Reactor Vessel and Internals Project Inspection and Flaw Evaluation Guidelines Implementation

Summary of Technical Information. During Unit 1's extended outage, the BWRVIP was initiated to develop inspection and flaw evaluation guidelines. The following guidelines will be implemented on Unit 1 during its restart.

BWRVIP-03 Reactor Pressure Vessel and Internals Examination Guidelines
BWRVIP-05 BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations
BWRVIP-06-A Safety Assessment of BWR Reactor Internals
BWRVIP-15 Configurations of Safety-Related BWR Reactor Internals
BWRVIP-18 BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines

BWRVIP-25 BWR Core Plate Inspection and Flaw Evaluation Guidelines
BWRVIP-26 BWR Top Guide Inspection and Flaw Evaluation Guidelines
BWRVIP-27-A BWR Standby Liquid Control System/Core Plate Inspection and Flaw Evaluation Guidelines
BWRVIP-38 BWR Shroud Support Inspection and Flaw Evaluation Guidelines
BWRVIP-41 BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines
BWRVIP-47 BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
BWRVIP-48 Vessel ID Attachment Weld Inspection and Flaw Evaluation
BWRVIP-49-A Instrument Penetration Inspection and Flaw Evaluation Guidelines
BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines
BWRVIP-75 Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules
BWRVIP-76 BWR Core Shroud Inspection and Flaw Evaluation Guidelines
BWRVIP-94 Program Implementation Guide
BWRVIP-104 Evaluation and Recommendations to Address Shroud Support Cracking in BWRs

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 with regard to the reactor vessel and internal inspection criteria will be resolved prior to Unit 1 restart by the implementation of the BWRVIP guidelines on Unit 1.

UFSAR Impact. The Unit 1 systems and AMPs impacted by this modification and their LRA sections:

- reactor vessel (3.1.2.2.16)
- reactor vessel internals (3.1.2.2.16)
- Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program (B.2.1.7)
- Boiling Water Reactor Penetrations Program (B.2.1.11)
- Boiling Water Reactor Vessel Internals Program (B.2.1.12)

It is reasonable to assume that the applicant will implement the BWRVIP guidelines. Without continued commitment to the BWRVIP, the applicant would have to independently develop and obtain staff approval of alternate methodologies for Unit 1, which is not economically feasible.

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and currently forcasted to be completed by November 2005.

Staff Evaluation. Prior to restart of Unit 1, the BWRVIP information included in the application will be implemented on Unit 1.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by November 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the BWRVIP and flaw evaluation guidelines implementation modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff has not identified any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.7 Anticipated Transients Without Scram

Description. Section 50.62 of 10 CFR requires applicants to reduce the risk from ATWS events. The applicant adopted the BWR Owners' Group recommendation for implementation of the ATWS rule by letter dated March 1, 1988. The staff approval of the applicant's approach for satisfying 10 CFR 50.62 was provided on January 22, 1989, and the associated TS changes were approved on January 26, 1989. TS 3.3.4.2 for the BFN units provides the requirements for the ATWS recirculation pump trip (ATWS-RPT) instrumentation. TS 3.1.7, SLC system, for the BFN units provides requirements for ATWS that satisfy 10 CFR 50.62. In its letter dated November 29, 1990, the applicant confirmed its commitment to install the required ATWS modifications prior to Unit 1 restart. Design features described in UFSAR Chapter 7.19 will be installed on Unit 1.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by implementation of the ATWS modifications on Unit 1. The CRD system will have a diverse scram (i.e. alternate rod injection) in accordance with LRA Section 2.3.3.29.

UFSAR Impact. The Unit 1 systems, structures, and commodities impacted by this modification and their LRA sections:

- reactor core isolation cooling (2.3.3.23)
- control rod drive (2.3.3.29)
- feedwater (2.3.4.3)
- primary containment structure (2.4.1.1)
- reactor buildings (2.4.2.1)
- electrical and instrumentation and control commodities (2.5.1)

Following resolution of this item, it is expected that the license renewal results shown with a bold-bordered box in the sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 analyses and modifications are scheduled for completion prior to restart. If for any reason, the applicant changes its planned actions to address 10 CFR 50.62, it will need to submit a revised TS change for staff approval and address the aging management aspects of the changes as necessary.

Staff Evaluation. After the implementation of the ATWS modifications on Unit 1 there will be no functional differences in the ATWS system between Units 1, 2, and 3. The Unit 1 components that perform the ATWS function will be incorporated into the appropriate AMPs specified in the LRA and there will be no unit-specific differences.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by May 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the ATWS modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.8 Reactor Vessel Head Spray

Description. The reactor vessel head spray piping is susceptible to IGSCC and was included in GL 88-01. The applicant responded to GL 88-01 for all three units by letter dated August 1, 1988. In that letter, the applicant notified the staff that it had previously removed the head spray piping from Units 2 and 3, and planned to remove the head spray piping from Unit 1 prior to startup. The staff's approval was provided on December 3, 1993. The applicant reconfirmed, in its July 21, 2004, supplemental response to GL 88-01 for Unit 1, that it planned to remove the reactor vessel head spray piping prior to Unit 1 restart.

On Units 2 and 3, the reactor vessel head spray piping within the drywell has been removed and the reactor vessel head penetration has a flanged cap installed. The primary containment isolation valves have been removed and the primary containment penetration has been sealed. Head spray piping has also been removed and a permanent welded cap has been installed at the RHR system interface with its head spray header.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by performing these head spray modifications on Unit 1. Once the head spray modifications are completed on Unit 1 prior to restart, the physical and operational differences between Unit 1 and Units 2 and 3 will be resolved

UFSAR Impact. The Unit 1 systems impacted by this modification and their LRA sections:

Reactor Vessel Internals (2.3.1.2)
Residual Heat Removal (2.3.2.4)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the LRA sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and currently forcasted to be completed by June 2006.

Staff Evaluation. After the implementation of the reactor vessel head spray modifications on Unit 1 there will be no functional differences in the reactor vessel head spray system between Units 1, 2, and 3. The Unit 1 components that perform the reactor vessel head spray function will be incorporated into the appropriate AMPs specified in the LRA, and there will be no unit-specific differences.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by June 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the reactor vessel head spray modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.9 Hardened Wetwell Vent

Description. In GL 89-16, dated September 1, 1989, the staff requested applicants with Mark I containments to voluntarily install a hardened wetwell vent. In response, the applicant committed, by letter dated October 30, 1989, to install a hardened wetwell vent prior to restart of each unit. The hardened wetwell vent has been installed on Units 2 and 3, but has not yet been implemented on Unit 1.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by the installation of the hardened wetwell vent on Unit 1. Once the modifications are completed, the physical and operational differences between Unit 1 and Units 2 and 3 will be resolved.

UFSAR Impact. The Unit 1 system and structure impacted by this modification and their LRA sections:

- containment (2.3.2.1)
- reinforced concrete chimney (2.4.6.1)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the sections identified above are applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and this modification is currently forcasted to be completed by May 2006. If for any reason, the applicant decided it would implement an alternate solution to GL 89-19, the applicant would be required to notify the staff, and include any alternate modifications within the appropriate AMPs.

Staff Evaluation. After the Unit 1 hardened wetwell vent modifications are completed, there will be no functional differences in the associated systems for Units 1, 2, and 3. The Unit 1 components that comprise the hardened wetwell vent will be incorporated into the appropriate AMPs specified in the LRA, and there will be no unit-specific differences.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by May 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the hardened wetwell vent modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.10 Service Air and Demineralized Water Primary Containment Penetrations

Description. The staff requested, by letter dated May 5, 1992, information regarding Unit 1 compliance with NUREG-0737, Item II.E.4.2; and 10 CFR Part 50, Appendix J. The staff compared the Unit 1 containment isolation scheme to the Unit 2 design and concluded, in the January 6, 1995, safety evaluation, that the isolation design was acceptable. Currently, the configuration of the Unit 1 primary containment penetrations numbers, X-20 and X-21, are different from the corresponding configuration on Units 2 and 3. On Unit 1 the penetrations are piped to the service air and demineralized water systems with primary containment isolation valves. On Units 2 and 3, they are capped and not assigned to a service system. These penetrations on Unit 1 will be capped and made identical to those of Units 2 and 3.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by making the Unit 1 configuration the same as the current Units 2 and 3 configuration. Once the service air and demineralized water systems modifications are completed on Unit 1, the physical and operational differences between Unit 1 versus Units 2 and 3 will be resolved.

If for any reason, the applicant decided it would not implement the committed modifications, the applicant would be required to notify the staff so that the following action to bring the item into the scope of managed piping would apply. The Unit 1 associated piping and components that are to be removed are shown on the Unit 1 boundary drawings and if the piping were not removed, the AMPs specified in the LRA would apply. Thus, there would be no change in the application if the committed modifications were not completed.

UFSAR Impact. The Unit 1 systems impacted by this modification and their LRA sections:

- service air (2.3.3.11)
- condensate and demineralized water (2.3.4.2)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the LRA sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and is currently forecasted to be completed by May 2006.

Staff Evaluation. After the modifications to the Unit 1 service air and condensate and demineralized systems piping are completed there will be no functional differences in the associated primary containment configurations for Units 1, 2, and 3.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by May 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the service air and demineralized water primary containment penetrations modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.11 Auxiliary Decay Heat Removal System

Description. As described in UFSAR 10.22, the ADHR system only serves Units 2 and 3. The only intended function for license renewal is to provide secondary containment integrity for the ADHR system’s piping that transfers the fuel pool heat.

The ADHR system provides an NSR means to remove decay heat and residual heat from the spent fuel pool and reactor cavity, and currently serves only Units 2 and 3. The ADHR allows servicing of the RHR system components earlier in an outage, thus, potentially reducing the outage duration. The only intended function for license renewal is to provide secondary containment integrity for the ADHR system's piping that transfers the fuel pool heat to the heat sink outside containment. There is currently only a single piping loop serving both Units 2 and 3 that penetrates the secondary containment.

The configuration of the ADHR system will be modified to service Unit 1 as well as Units 2 and 3. When modified, there will continue to be only a single piping loop that penetrates the secondary containment. That loop and its secondary containment penetrations will serve all three units.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by modifying the ADHR system to service Unit 1 as well as Units 2 and 3. When modified, there will continue to be only a single piping loop that penetrates the secondary containment. That loop and its secondary containment penetrations will serve all three units. Once the ADHR modifications are completed on Unit 1 prior to restart, the physical and operational differences between Unit 1 and Units 2 and 3 will be resolved.

UFSAR Impact. The Unit 1 system impacted by this modification and its LRA sections and table is the auxiliary decay heat removal system (2.3.3.24 and 3.3.2.1.24 and Table 3.3.2.24).

Following resolution of this item, the license renewal results shown with a bold-bordered box in the LRA sections and table identified above will be applicable to Unit 1. Should the applicant not make the modifications discussed above, the applicant would be required to notify the staff. Since these associated additional components planned to be installed would not be installed, the boundary drawings for Unit 1 would not change, and the additional components would not be included within the appropriate AMPs as currently planned.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to Unit 1 restart and is currently projected to be complete by May 2005.

Staff Evaluation. After the modifications to the ADHR system are completed there will be no functional differences in the system for Units 1, 2, and 3.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by May 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the ADHR system modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the

SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.12 Maintenance Rule

Description. By letter dated August 9, 1999, the staff issued a partial temporary exemption. This exempts the applicant from the specific scoping requirements of 10 CFR 50.65(b) and allows it to maintain the defueled and long-term layup status of Unit 1. The exemption does not impact Maintenance Rule scoping for equipment required to be functional to support Unit 1 in its defueled status or equipment required to support operation of Units 2 and 3.

The scoping results for the affected SSCs will not be changed. No changes are expected for AMR results or TLAAs.

The temporary exemption expires upon restart of Unit 1.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved upon the restart of Unit 1, when the temporary exemption ceases to be effective. Specifically, with respect to the CLB differences identified in the application, the differences in the Maintenance Rule implementation will be resolved.

UFSAR impact. There are no Unit 1 systems impacted by this modification because Unit 1 SSCs not required to be functional during the current shutdown and defueled status are not included within the scope of the Maintenance Rule.

Schedule for Completion. The committed completion date is at Unit 1 restart because the temporary exemption will expire upon Unit 1 restart and the full scope of the Maintenance Rule will apply to Unit 1.

Staff Evaluation, After the Maintenance Rule modifications are completed upon Unit 1 restart, there will be no functional differences in the system for Units 1, 2, and 3.

As stated above, this modification is forcasted to be completed upon Unit 1 restart, and it will be duly tracked by a separate LRA Appendix A commitment and LRA inspection prior to restart to confirm implementation.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by Unit 1 restart. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the Maintenance Rule modification. The scoping and screening reviews were done based on the

CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.1.13 Reactor Water Cleanup System

Description. BFN has selected an option in the RWCU System Program that allows the applicant not to test system piping outboard of the outboard primary containment isolation valve provided that the following actions are completed:

- The RWCU piping outside the outboard primary containment isolation valves will be replaced with IGSCC-resistant piping
- The actions requested in GL 89-10 SR Motor-Operated Valve Testing and Surveillance, will be satisfactorily completed for the RWCU system; and, in addition, the RWCU system will be reconfigured so that the pumps are no longer exposed to a high temperature environment, consistent with Units 2 and 3.

The applicant committed to replace the 4-inch and larger, stainless steel, RWCU piping located outside the drywell prior to the restart of Unit 1. The applicant also committed to develop and implement a comprehensive Motor-operated Valve Testing and Surveillance Program for Unit 1, satisfying the intent of GL 89-10. At the time of its restart, the Unit 1 RWCU system will have been reconfigured so that the pumps are no longer exposed to a high-temperature environment.

Difference Resolution. The differences between the CLB for Unit 1 and the CLB for Units 2 and 3 will be resolved prior to Unit 1 restart by performing the actions described above. Once these actions have been implemented, there will be no operational differences between the Unit 1 RWCU system and the Units 2 and 3 systems.

UFSAR Impact. The Unit 1 system and AMP impacted by this modification and their LRA sections:

- reactor water cleanup (2.3.3.21)
- Reactor Water Cleanup System Program (B.2.1.22)

Following resolution of this item, the license renewal results shown with a bold-bordered box in the LRA sections identified above will be applicable to Unit 1.

Schedule for Completion. The Unit 1 modification is scheduled for completion prior to restart and is currently projected to be complete by July 2006.

The applicant will have completed the above commitments prior to Unit 1 restart since the piping has been removed and the system is being reconfigured as described above. Other license conditions will not allow the applicant to enter the period of extended operation without implementing this modification

Staff Evaluation. Prior to the restart of Unit 1, the applicant will have completed replacement of the RWCU system piping outside the outboard primary containment isolation valves, and completed implementation of its GL 89-10 program, such that the Unit 1 differences identified in the application in this regard are no longer applicable.

In its submittal dated January 31, 2005, the applicant forcasted that this modification will be completed by July 2006. This commitment will be tracked through a temporary instruction TI-2509-01 as a part of the license application verification that this commitment will be completed prior to Unit 1 restart. Other license conditions will not permit the applicant to enter the period of extended operation without implementing this modification.

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 structures and components because of the reactor water cleanup system modification. The scoping and screening reviews were done based on the CLB. The differences between the units' CLBs that are relevant to the application will be resolved prior to Unit 1 restart. The Unit 1 systems and structures impacted by this modification, and their LRA sections and tables as indicated in the list above, were evaluated elsewhere in the SER, and the staff did not identify any omissions or discrepancies. Therefore, the staff concluded that the applicant had adequately identified the Unit 1 SSCs within the scope of license renewal, as required by 10 CFR 54.4 (a), and the SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6.2 Staff Evaluation

The staff evaluation of LRA Appendix F items used the methodology described in SER Section 2.6.1 to determine whether these items had been adequately scoped and screened. The staff did not perform any safety review of any of these modifications, but performed a limited disposition of the resolution activities for each of the LRA Appendix F items that will be completed prior to Unit 1 restart. As stipulated and agreed upon with the staff in its pre-application meetings, the applicant provided in its submittal dated January 31, 2005, “Additional Information Concerning the Integration of Unit 1 Restart and License Renewal Activities,” a status update on completion of the restart activities that impact the CLB of Unit 1. The SER with OI presents the latest information on these modifications. Accordingly, the staff found that the disposition and validation of the modifications were consistent with the commitments. The staff will track modifications and implementation details of these items via separate LRA inspections prior to Unit 1 restart to confirm implementation.

In reviewing the technical information provided in LRA Appendix F, the staff review was limited to verifying:

(i) The sufficiency of information provided by the applicant for the 13 items that impacted the LRA review.

(ii) The applicability of the 13 items to Unit 1.

(iii) The systems these 13 items impact.

(iv) The plan to resolve differences between the CLB for Unit 1 and the CLB for Units 2 and 3, so that upon restart all units will have the same CLB.

It should be noted that in the LRA the restart activities listed in LRA Appendix F were generally referred to as differences in the design basis or licensing basis. Based on the definition of CLB in 10 CFR 54.3, these activities are more precisely described as implementation activities of the design and licensing basis. Even though each of the 13 activities listed in LRA Appendix F is committed to and planned for completion prior to Unit 1 restart, any unimplemented commitments would remain valid, part of the CLB, carry over into the renewed license period, and be controlled by the NRC regulatory and oversight process.

The staff's evaluation of the information provided in the LRA was performed in the same manner for all mechanical, civil, and electrical systems as it relates to the particular item in question. The objective of the review was to determine if the components and supporting structures for a specific mechanical system that appeared to meet the scoping criteria specified in the Rule were identified by the applicant as being within the scope of license renewal. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.6.3 Conclusion

The restart plan ensures compliance with the applicant’s commitments made during the shutdown and with regulatory requirements that changed during the extended shutdown. In addition, a license condition will be imposed as part of LRA review that will require the Unit 1 restart activities, described in LRA Appendix F, to be completed prior to Unit 1 restart. Therefore, while implementation of the 13 items identified in LRA Appendix F is not yet complete, the staff found that this will not be a barrier to staff approval of license renewal for Unit 1. This type of approval has not been made for commitments in prior LRAs approved by the staff. Therefore, there are no staff evaluations or staff findings performed for these 13 LRA Appendix F items, except for restating the technical information provided in the LRA and the January 31, 2005, letter, in the format described below and a status update on the physical implementation of these Unit 1 restart activities.

During its review of the information provided in LRA Appendix F, the staff did not identify any omissions or discrepancies in the applicant’s integration of Unit 1 restart activities with license renewal activities. Therefore, the staff concluded that, pending satisfactory implementation of the activities identified in LRA Appendix F prior to Unit 1 restart, the applicant had adequately identified the Unit 1 systems, structures, and components that will be within the scope of license renewal, as required by 10 CFR 54.4(a), and the Unit 1 structures and components that will be subject to an AMR, as required by 10 CFR 54.21(a)(1). Satisfactory completion of these actions prior to Unit 1 restart will be a condition of the renewed license.

2.7 Conclusion for Scoping and Screening

The staff reviewed the information in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation and Results." The staff determined that the applicant's scoping and screening methodology, including its supplement 10 CFR 54.4(a)(2) review which brought additional NSR piping segments and associated components into the scope of license renewal, was consistent with the requirements of 10 CFR 54.21(a)(1) and the staff's position on the treatment of SR and NSR SSCs within the scope of license renewal and the structures and components requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

On the basis of its review, the staff concluded that the applicant had adequately identified those systems and components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those systems and components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

With regard to these matters, the staff concluded that there is reasonable assurance that the activities authorized by the renewed license can continue to be conducted in accordance with the CLB, and any changes made to the BFN CLB, in order to comply with 10 CFR 54.29(a), are in accord with the Act and the Commission's regulations.

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SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) contains the staff's evaluation of the applicant's AMPs (AMPs) and aging management reviews (AMRs). In License Renewal Application (LRA) Appendix B, the applicant described the 39 AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures.

In LRA Section 3, the applicant provided the results of the AMRs for those structures and components that were identified in LRA Section 2 as being 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, Tennessee Valley Authority (TVA, the applicant) credited U.S. Nuclear Regulatory Commission Regulatory Guide (NUREG)-1801, "Generic Aging Lessons Learned [GALL] Report," dated July 2001. The GALL Report contains the Nuclear Regulatory Commission's (NRC or the staff's) generic evaluation of the existing plant programs, and it documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the period of extended 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 structures or components 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 a license renewal application to demonstrate that the programs at its facility correspond to those reviewed and approved in the GALL Report.

The purpose of the GALL Report is to provide the staff with a summary of staff-approved AMPs to manage or monitor the aging of structures and components that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a reference for applicants and staff reviewers to quickly identify those AMPs and activities that the staff determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies (1) systems, structures, and components (SSCs), (2) structure and component (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 based on this process. The results of the demonstration project confirmed that the GALL process will improve the efficiency and effectiveness of the LRA review, while maintaining the staff's focus on public health and safety. NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications," (SRP-LR), dated April 2001, was prepared based on both the GALL Report model and lessons learned from the demonstration project.

The staff performed its review in accordance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and the guidance provided in the SRP-LR and the GALL Report.

The staff performed onsite audits at the applicant's offices in Chattanooga, TN, during the weeks of June 25 and July 19, 2004, and additional technical reviews of the applicant's AMPs and AMRs. The objective of the audits and reviews was to verify that the effects of aging on structures and components will be adequately managed so that their intended functions will be maintained consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Detailed results of the staff's onsite audits are documented in "Audit Report for Plant AMPs and Aging Management Reviews - Browns Ferry Nuclear Plant Units 1, 2, and 3," dated April 26, 2005.

3.0.1 Format of the License Renewal Application

TVA 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, ML030990052). This revised LRA format incorporates lessons learned from the staff's reviews of the previous five LRAs. These previous LRAs used a format developed from information gained during an NRC staff and NEI demonstration project that was conducted to evaluate the use of the GALL Report in the staff's review process.

The organization of LRA Section 3 parallels Chapter 3 of the SRP-LR. The AMR results information in LRA Section 3 is presented in the following two table types:

- Table 1: Table 3.x.1 – where "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 LRA Section 3.
- Table 2: Table 3.x.2-y – where "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, "2" indicates that this is the second table type in LRA Section 3, and "y" indicates the system table number.

The content of the previous applications and the Browns Ferry Nuclear Plant (BFN) application is essentially the same. The intent of the revised format used for the BFN application was to modify the tables in Chapter 3 to provide additional information that would assist the staff in its review. In Table 1, TVA summarized the portions of the application that it considered to be consistent with the GALL Report. In Table 2, TVA 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 of how the facility aligns with the corresponding tables of 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 the “Type” column has been replaced by an “Item Number” column and the “Item Number in GALL” column has been replaced by a “Discussion” column. The “Item Number” column provides the reviewer with a means to cross-reference from Table 2 to Table 1. The “Discussion” column is used by the applicant to provide clarifying and amplifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended – information or reference to where that information is located
- the name of a plant-specific program being used
- exceptions to the GALL Report assumptions
- a discussion of how the line is consistent with the corresponding line item in the GALL Report when this may not be intuitively obvious
- a discussion of how the item is different than the corresponding line item in the GALL Report (e.g., 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 the consistency can be easily checked.

3.0.1.2 Overview of Table 2

Table 3.x.2-y (Table 2) provides the detailed results of the AMRs for those components identified in LRA Section 2 as being subject to an AMR. The LRA contains a Table 2 for each of the components or systems within a system grouping (e.g., reactor coolant systems, engineered safety features, auxiliary systems, etc.). For example, the engineered safety features group contains tables specific to the containment spray system, containment isolation system, and emergency core cooling system, Table 2 consists of the following nine columns:

1. Component Type - The first column identifies all of the component types from Section 2 of the LRA that are subject to AMR. They are listed in alphabetical order.
2. Intended Function - The second column contains the license renewal intended functions (using abbreviations where necessary) for the listed component types. Definitions and abbreviations of passive component type intended functions are presented in Table 2.0.1, Intended Function Abbreviations and Definitions.
3. Material - The third column lists the particular materials of construction for the component type.
4. Environment - The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated, as appropriate. Descriptions of the internal and external service environments that were used in the AMR to determine aging effects requiring management are included in Table 3.0.1, Internal Service Environments, and Table 3.0.2, External Service Environments.

5. Aging Effect Requiring Management (AERM) - As part of the AMR process, the applicant determines any aging effects requiring management for the material and environment combination in order to maintain the intended function of the component type. These aging effects requiring management are listed in column five.

6. AMPs - The AMPs used to manage the aging effects requiring management are listed in column six of Table 2.

7. GALL Volume 2 Item - Each combination of component type, material, environment, AERM, and AMP that is listed in Table 2 is compared to the GALL Report, Volume 2 with consideration given to the standard notes, to identify consistencies. When they are identified, they are documented by noting the appropriate GALL Report, Volume 2 item number in column seven of Table 2. If there is no corresponding item number in the GALL Report, Volume 2, this row in column seven has "None." That way, a reviewer can readily identify where there is correspondence between the plant-specific tables and the GALL Report, Volume 2 tables.

8. Table 1 Item - Each combination of component, material, environment, AERM, and AMP that has an identified NUREG-1801 Volume 2 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in column eight of Table 2. If there is no corresponding item in the GALL Report, Volume 1, this row in column eight has "None." That way, the information from the two tables can be correlated.

9. Notes - In order to realize the full benefit of the GALL Report, BFN has aligned the information in the Tables 3.x.2.y with the information in NUREG-1801 Volume 2 using a series of notes. Notes that utilize letter designations are industry-standard notes taken from the Proposed Standard License Renewal Application Format Package (Letter from Alexander Marion (NEI) to Dr. P. T. Kuo (NRC), Project Number: 690, dated August 20, 2003). Notes that use numeric designations are BFN plant-specific notes.

3.0.2 Staff's Review Process

The staff conducted the following three types of evaluations of the AMRs and associated AMPs:

1. For items the applicant states are consistent with the GALL Report, the staff conducted an audit.

2. For items the applicant states are consistent with the GALL Report with exceptions, the staff conducted an audit of the item and of the applicant's technical justification for the exceptions.

3. For items that are not consistent with the GALL Report, the staff conducted a technical review.

3.0.2.1 Review of AMPs

For those AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify that the applicant's AMPs were consistent with the AMPs in the GALL Report. For each AMP that had one or more deviations, the staff evaluated each deviation to determine: (1) whether the deviation was acceptable; and

(2) whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited. For AMPs that were not evaluated in the GALL Report, 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 SRP-LR Appendix A.

1. Scope of Program - Scope of the program should include the specific structures and components subject to an AMR for license renewal.
2. Preventive Actions - Preventive actions should prevent or mitigate aging degradation.
3. Parameters Monitored or Inspected - Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended functions(s).
4. Detection of Aging Effects - Detection of aging effects should occur before there is a loss of structure or 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 a timely detection of aging effects.
5. Monitoring and Trending - Monitoring and trending should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.
6. Acceptance Criteria - Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB design conditions during the period of extended operation.
7. Corrective Actions - Corrective actions, including root cause determination and prevention of recurrence, should be timely.
8. Confirmation Process - Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative Controls - Administrative controls should provide a formal review and approval process.
10. Operating Experience - Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in the BFN audit and review report and are summarized in SER Section 3.0.3.

The staff reviewed the applicant's Corrective Action Program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the Corrective Action Program included assessment of the following program elements: (7) corrective actions, (8) confirmation process, and (9) administrative controls.

The staff reviewed the information concerning the (10) operating experience program elements and documented its evaluation in the BFN audit and review report. The staff also included a summary of the program in SER Section 3.0.3.

The staff reviewed the updated final safety analysis report (UFSAR) supplement for each AMP to determine if it provided an adequate description of the program or activity, as required by 10 CFR 54.21(d).

3.0.2.2 Review of AMR Results

Table 2 of the LRA contains information concerning whether or not the AMRs align with the AMRs identified in the GALL Report. For a given AMR in Table 2, the NRC staff reviewed the combination of intended function, material, environment, AERM, and AMP for a particular component type within a system. The Table 2 AMRs that correlate with an AMR in the GALL Report are identified by a reference item number in column seven, "GALL, Volume 2 Item." The eighth column, "Table 1 Item," provides a reference number that indicates the corresponding row in Table 1.

The staff conducted an audit to verify the appropriateness of the applicant's AMR correlations to the GALL Report. A blank column seven indicates that the applicant was unable to locate an appropriate corresponding AMR in the GALL Report. The staff conducted a technical review of those Table 2 AMRs that are not consistent with the GALL Report.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR, for the AMRs and associated AMPs that it reviewed, the staff also reviewed the UFSAR supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In performing its review, the staff relied heavily on the LRA, the LRA supplements, the SRP-LR, and the GALL Report.

Also, during the onsite audit, the staff examined the applicant's justification, as documented in the staff's BFN audit and review report, to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. 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 LRA Appendix B. The table also indicates the GALL Report with which the applicant claimed its AMP was consistent (if applicable) and the SSCs that credit the AMP for managing or monitoring aging. The section of the SER, in which the staff's evaluation of the program is documented, is also provided.

Table 3.0.3-1 BFN's Aging Management Programs

BFN's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Existing AMPs				
Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (B.2.1.2)	Not consistent - exceptions taken	XI.E2	Electrical and instrumentation and controls	3.0.3.2.1
ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)	Consistent	XI.M1	Reactor vessel, internals, and reactor coolant system; containments, structures, and component supports; engineered safety features systems; auxiliary systems; steam and power conversion systems	3.0.3.1.3
Chemistry Control Program (B.2.1.5)	Not consistent - exceptions and enhancements taken	XI.M2	Reactor vessel, internals, and reactor coolant system; engineered safety features systems; auxiliary systems; steam and power conversion systems; containments, structures, and component supports	3.0.3.2.2
Reactor Head Closure Studs Program (B.2.1.6)	Consistent	XI.M3	Reactor vessel, internals, and reactor coolant system	3.0.3.1.4
Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program (B.2.1.7)	Consistent with enhancements	XI.M4	Reactor vessel, internals, and reactor coolant systems	3.0.3.2.3
Boiling Water Reactor Feedwater Nozzle Program (B.2.1.8)	Consistent with enhancements	XI.M5	Reactor vessel, internals, and reactor coolant systems	3.0.3.2.4
Boiling Water Reactor Control Rod Drive Return Line Nozzle Program (B.2.1.9)	Consistent	XI.M6	Reactor vessel, internals, and reactor coolant systems	3.0.3.1.5

BFN's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Boiling Water Reactor Stress Corrosion Cracking Program (B.2.1.10)	Consistent with enhancements	XI.M7	Reactor vessel, internals, and reactor coolant systems; engineered safety features; auxiliary systems; steam and power conversion system	3.0.3.2.5
Boiling Water Reactor Penetrations Program (B.2.1.11)	Consistent with enhancements	XI.M8	Reactor vessel, internals, and reactor coolant systems	3.0.3.2.6
Boiling Water Reactor Vessel Internals Program (B.2.1.12)	Consistent with enhancements	XI.M9	Reactor vessel, internals, and rector coolant systems	3.0.3.2.7
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program (B.2.1.14)	N/A	XI.M13	N/A	3.0.3.2.8
Flow-Accelerated Corrosion Program (B.2.1.15)	Consistent with enhancements	XI.M17	Steam and power conversion systems; engineered safety features systems	3.0.3.2.9
Bolting Integrity Program (B.2.1.16)	Not consistent - exceptions taken	XI.M18	Reactor vessel, internals, and reactor coolant systems; engineered safety features systems; auxiliary systems; steam and power conversion systems	3.0.3.2.10
Open-Cycle Cooling Water Program (B.2.1.17)	Consistent with enhancements	XI.M20	Auxiliary systems	3.0.3.2.11
Closed-Cycle Cooling Water System Program (B.2.1.18)	Consistent with enhancements	XI.M21	Auxiliary systems	3.0.3.2.12
Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.1.20)	Not consistent - exceptions taken	XI.M23	Auxiliary systems	3.0.3.2.13
Compressed Air Monitoring Program (B.2.1.21)	Consistent with enhancements	XI.M24	Auxiliary systems; steam and power conversion systems	3.0.3.2.14
BWR Reactor Water Cleanup System Program (B.2.1.22)	Consistent with enhancements	XI.M25	Auxiliary systems	3.0.3.2.15

BFN's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Fire Protection Program (B.2.1.23)	Not consistent - exceptions and enhancements taken	XI.M26	Auxiliary systems; containments, structures, and component supports	3.0.3.2.16
Fire Water System Program (B.2.1.24)	Not consistent - exceptions and enhancements taken	XI.M27	Auxiliary systems	3.0.3.2.17
Aboveground Carbon Steel Tanks Program (B.2.1.26)	Consistent	XI.M29	Steam and power conversion systems	3.0.3.1.6
Fuel Oil Chemistry Program (B.2.1.27)	Not consistent - exceptions and enhancements taken	XI.M30	Auxiliary systems	3.0.3.2.18
Reactor Vessel Surveillance Program (B.2.1.28)	Consistent with enhancements	XI.M31	Reactor vessel, internals, and reactor coolant system	3.0.3.2.19
Buried Piping and Tanks Inspection Program (B.2.1.31)	Consistent	XI.M34	Engineered safety feature systems; auxiliary systems	3.0.3.1.9
ASME Code Section XI Subsection IWE Program (B.2.1.32)	Not consistent - exceptions and enhancement taken	XI.S1	Containments, structures, and component supports	3.0.3.2.20
ASME Code Section XI Subsection IWF Program (B.2.1.33)	Consistent (letter dated January 18 and 24, 2005)	XI.S3	Containments, structures, and component supports	3.0.3.2.21
10 CFR 50 Appendix J Program (B.2.1.34)	Consistent	XI.S4	Containments, structures, and component supports	3.0.3.1.10
Masonry Wall Program (B.2.1.35)	Consistent with enhancements	XI.S5	Containments, structures, and component supports	3.0.3.2.22
Structures Monitoring Program (B.2.1.36)	Consistent with enhancements	XI.S6	Containments, structures, and component supports	3.0.3.2.23
Inspection of Water-Control Structures Program (B.2.1.37)	Consistent with enhancements	XI.S7	Containments, structures, and component supports	3.0.3.2.24

BFN's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Systems Monitoring Program (B.2.1.39)	Plant-specific	N/A	Reactor coolant systems; engineered safety features systems; auxiliary systems; steam and power conversion systems	3.0.3.3.1
Diesel Starting Air Program (B.2.1.41)	Plant-specific	N/A	Auxiliary systems	3.0.3.3.3
Environmental Qualification Program (B.3.1)	Consistent with enhancements	X.E1	Electrical and instrumentation and controls	3.0.3.2.25
Fatigue Monitoring Program (B.3.2)	Consistent with enhancements	X.M1	Reactor vessel, internals, and reactor coolant systems; containment, structures, and component supports	3.0.3.2.26
New AMPs				
Accessible Non-Environmental Qualification Cables and Connections Inspection Program (B.2.1.1)	Consistent	XI.E1	Electrical and instrumentation and controls	3.0.3.1.1
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.1.3)	Consistent	XI.E3	Electrical and instrumentation and controls	3.0.3.1.2
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.2.1.13)	N/A		Main steam line flow-restricting venturis	3.0.3.3.4
One-Time Inspection Program (B.2.1.29)	Consistent	XI.M32	Reactor vessel, internals, and reactor coolant systems; engineered safety feature systems; auxiliary systems; steam and power conversion systems; containment, structures and component supports	3.0.3.1.7
Selective Leaching of Materials Program (B.2.1.30)	Consistent	XI.M33	Engineered safety feature systems; auxiliary systems; steam and power conversion systems	3.0.3.1.8

BFN's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Bus Inspection Program (B.2.1.40)	Plant-specific	N/A		3.0.3.3.2
Unit 1 Periodic Inspection Program (B.2.1.42)	Plant-specific	N/A	Un-replaced, un-refurbished piping and components for Unit 1 only	3.0.3.3.5

3.0.3.1 AMPs That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

In LRA Appendix B, the applicant identified that the following AMPs were consistent with the GALL Report:

- Accessible Non-Environmental Qualification Cables and Connections Inspection Program (B.2.1.1)
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.1.3)
- ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- Reactor Head Closure Studs Program (B.2.1.6)
- Boiling Water Reactor Control Rod Drive Return Line Nozzle Program (B.2.1.9)
- Aboveground Carbon Steel Tanks Program (B.2.1.26)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- 10 CFR 50 Appendix J Program (B.2.1.34)

During its audit and review, conducted June 21 to 25, 2004, the staff confirmed the applicant's claim of consistency with the GALL Report. As a result of this review, the staff identified issues for several of the AMPs that were resolved with a docketed response from the applicant. Those issues and resolutions are discussed in Sections 3.0.3.1.1 to 3.0.3.1.10, below.

3.0.3.1.1 Accessible Non-Environmental Qualification Cables and Connections Inspection Program

Summary of Technical Information in the Application. The applicant's Accessible Non-Environmental Qualification (Non-EQ) Cables and Connections Inspection Program is described in LRA Section B.2.1.1, "Accessible Non-Environmental Qualification Cables and Connections Inspection Program." In the LRA, the applicant stated that this is a new program that will be initiated prior to the period of extended operation. This commitment is identified on the applicant’s license renewal commitment list as Item No. 1. This program is consistent with GALL AMP XI.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

As a result of this review, the staff identified two issues discussed below that were resolved with a docketed response from the applicant.

1. GALL AMP XI.E1 recommends that the program be written specifically to address cables and connections at plants whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. However, the applicant’s description of the Accessible Non-EQ Cables and Connections Inspection Program does not address the percentage of cables in adverse localized environments at BFN that are accessible.

   The applicant stated, as documented in the staff’s audit and review report that, based upon a search of as designed data in the current cable routing database, greater than 50 percent of cables are located in accessible cable trays.

   The staff found the applicant’s response acceptable since more than 50 percent of the cables will be accessible for inspection, which is consistent with the recommendations for GALL AMP XI.E1.

2. The description of GALL AMP XI.E1 states that the technical basis for the sample of cables and connections selected for inspection is to be provided. However, the staff noted that the description of the Accessible Non-EQ Cables and Connections Inspection Program in the LRA does not address the rationale for selecting the sample of cables and connections to be inspected.

   In its response to the request for additional information (RAI) 3.6-6, dated December 9, 2004, the applicant stated that the scope of the program will include a representative sample of accessible, insulated cables and connections within the scope of license renewal will be visually inspected in adverse localized environments as identified by a review of operating experience. The sample will include cables in raceways located in the drywell that are qualified to the IEEE 383-1974 flame test and not coated with Flamemastic. Selected cables and connections from accessible areas (the inspection sample) will represent, with reasonable assurance, all cables and connections in adverse localized environments.

Operating Experience: The applicant stated in the LRA that the Accessible Non-EQ Cables and Connections Inspection Program is a new program for which there is no operating experience. The operating experience data associated with implementing this program will be addressed in the applicant's Corrective Action Program. In evaluating the element, the applicant stated that the implementation of the Accessible Non-EQ Cables and Connections Inspection Program will provide reasonable assurance that the applicable aging effects will be effectively managed so that the structures and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

UFSAR Supplement. In LRA Section A.1.1, the applicant provided the UFSAR supplement for the Accessible Non-EQ Cables and Connections Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement sufficient, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

Summary of Technical Information in the Application. The applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is described in LRA Section B.2.1.3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program." In the LRA, the applicant stated that this is a new program that will be initiated prior to the period of extended operation. This program is consistent with GALL AMP XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will manage the aging effects of inaccessible medium-voltage cables that are not subject to the EQ requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized. The applicant also stated that the specific type of test performed will be determined prior to the initial test and will be a proven test for detecting deterioration of the insulation system due to wetting. The test will be as described in Electric Power Research Institute (EPRI) TR-103834-P1-2 or will be a test that is state-of-the-art at the time of program implementation.

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a condition monitoring program in which medium voltage cables that are installed in underground conduit duct banks and that perform an intended function within the scope of license renewal (such as the medium voltage cables to the residual heat removal service water (RHRSW) pumps) will be tested 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 and will be a proven test for detecting deterioration of the insulation system due to wetting.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.1.3, regarding the applicant's demonstration of the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff’s review of LRA Section B.2.1.3 identified an area in which additional information was necessary to complete the review of the applicant’s program elements. The applicant responded to the staff’s RAI as discussed below.

In RAI 3.6-3, dated November 4, 2004, the staff stated it reviewed the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program credited for managing the effects for non-EQ inaccessible medium voltage cables. Therefore, staff requested the applicant to provide (1) a list of cables that are covered under this program, (2) any plant and/or industry operating experience regarding the water-treeing phenomenon or any anticipated decrease in the dielectric strength of the conductor insulation, and (3) a description of the 10 elements of the proposed AMP.

The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below:

1. Scope of Program - In its response to the staff RAI 3.6-3 as above and by letter dated December 9, 2004, the applicant stated that medium voltage cables that are installed in underground conduit duct banks and that perform an in-scope intended function (such as the medium voltage cables to RHRSW pumps) will also be included in this program. The staff finds the above response to be acceptable since the Non-EQ Inaccessible Medium voltage Cable Program will require testing of all in-scope cables included in the program.

2. Preventive Actions - Periodic actions, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed, will be taken to prevent cables from being exposed to significant moisture. These actions will be performed as part of the testing described in Parameters Monitored or Inspected. The staff finds that the inspection of water collection in cable manholes and conduit at a ten year frequency is not adequate. The staff indicated that the frequency of inspection for water collection in cable manholes and conduit should be yearly. The staff asked the applicant to explain why every ten years inspection is sufficient. On January 18, 2005, the applicant stated that inspection for water collection for in-scope cable manholes and conduits will be adjusted to be performed annually. Based on the above, the staff's concern is resolved.

3. Parameters Monitored or Inspected - This program will test those inaccessible medium voltage cables identified as in scope to determine the condition of the conductor insulation by testing the cables. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-art at the time. The staff finds this to be acceptable since this is consistent with the GALL XI.E3 program.

4. Detection of Aging Effects - Affected cables will be tested before the current 40-year licensing term has concluded for each unit and at least once every 10 years thereafter. The staff finds this to be acceptable since this is consistent with the GALL XI.E3 program.

5. Monitoring and Trending - Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Test results that are trendable may be trended to provide additional information on the rate of degradation. The staff finds this to be acceptable since this is consistent with GALL XI.E3 program.

6. Acceptance Criteria - During testing, cables shall meet the acceptance criteria of the test being performed. The staff finds this to be acceptable since this is consistent with the GALL XI.E3 program.

7. Operating Experience - Industry operating experience was incorporated into the license renewal process through a review of industry documents to identify aging effects and mechanisms that could challenge the intended function of components within the scope of this program. Review of plant-specific operating experience was also performed to identify aging effects experienced. This review involved electronic database searches of plant information including problem evaluation reports (PERs), staff communications, RAIs, and work orders (WOs). As a result of the search, the following documents were reviewed with no new aging effects identified: Information Notice (IN) 86-49, RIS 2000-25, and RAIs 1554 through 1558 (Peach Bottom Units 1 and 2).

On the basis of its review of the above operating experience, the staff concluded that the applicant's program for Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program adequately manages the aging effects that have been observed at the applicant's plant. Therefore, the staff’s concern described in RAI 3.6-3 is resolved.

UFSAR Supplement. In LRA Section A.1.3, and subsequent LRA supplements, the applicant provided the UFSAR supplement for the applicant's program for Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program and RAI response, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program

Summary of Technical Information in the Application. The applicant’s American Society of Mechanical Engineers (ASME) Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program is described in LRA Section B.2.1.4, “ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program.” In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

In the LRA, the applicant stated that the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program includes periodic visual, surface, and/or volumetric examination of Class 1, 2, and 3 pressure-retaining components and their integral attachments. Requirements for ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program are mandated by the BFN Technical Requirements Manual 3.4.3, "Structural Integrity." Section 50.55a of 10 CFR imposes the inservice inspection requirements of the ASME Code Section XI for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water-cooled power plants.

<u>Staff Evaluation</u>. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

Based on its review, the staff concluded that the applicant's ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program provides reasonable assurance of aging management. As a result of this review, the staff identified two issues discussed below that were resolved with a docketed response from the applicant.

1. The staff noted that ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program did not indicate what the IWB, IWC, and IWD commitment will be for Unit 1 restart baseline inspections, after restart, and during the extended period of operation.

   The applicant stated, as documented in the staff's audit and review report, that the re-baseline inspection scope includes all inspections required during a typical 10-year inspection interval for Class 1, 2, and 3 components that have not been repaired or replaced. The code of record for Unit 1 recovery is the 1995 Edition with Addenda through 1996 of ASME Code Section XI. Following restart, the current (suspended) inservice inspection (ISI) interval will be completed. The next inspection interval will meet the requirements of 10 CFR 50.55(a) at that time. For the period of extended operation, the Code edition will be consistent with 10 CFR 50.55(a) requirements for all three units.

   The staff found the applicant's response acceptable on the basis that all three units will be consistent with the GALL Report during the extended period of operation and the Unit 1 re-baseline program will provide reasonable assurance that the condition of Unit 1 piping and components is comparable to that of Units 2 and 3.

2. In LRA Section B.2.1.4, the applicant stated that currently approved relief requests and approved code cases are used. The staff noted that these are not applicable to the period of extended operation and asked the applicant to confirm that the commitment to implement the requirements of 10 CFR 50.55(a) for license renewal is not modified by the current relief requests or implementation of currently approved code cases.

   The applicant stated, as documented in the staff's audit and review report, that the commitment to implement the requirements of 10 CFR 50.55(a) for license renewal is not modified by the current relief requests or implementation of currently approved Code cases; that there are currently no relief requests that extend past the 40-year period; and, that relief requests that extend into the period of license renewal will be in accordance with 10 CFR 50.55(a).

The staff found the applicant's response acceptable on the basis that current approved relief requests and code cases will not in any way modify the applicant's commitment to implement 10 CFR 50.55a during the period of extended operation.

Operating Experience. The ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program in accordance with Subsections IWB, IWC, or IWD has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments.

The applicant successfully identified indications of age-related degradation prior to the loss of the functions of the components, and has taken appropriate corrective actions through evaluation, repair, or replacement of the components in accordance with ASME Section XI and station implementing procedures.

UFSAR Supplement. In LRA Section A.1.4, the applicant provided the UFSAR supplement for the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Reactor Head Closure Studs Program

Summary of Technical Information in the Application. The applicant's Reactor Head Closure Studs Program is described in LRA Section B.2.1.6, "Reactor Head Closure Studs Program." In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.M3, "Reactor Head Closure Studs Program."

In the LRA, the applicant stated that the Reactor Head Closure Studs Program includes (1) inservice inspection in conformance with the requirements of the ASME Code Section XI Subsection IWB, Table IWB 2500-1 (B.2.1.4), and (2) preventive measures to mitigate cracking. The applicant stated that (1) the preventive measures of regulatory guide (RG) 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," have been implemented, and (2) approved lubricants minimize the potential for cracking of the non-metal-plated reactor head closure studs.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

Operating Experience. In LRA Section B.2.1.6, the applicant evaluated the program element operating experience and stated that stress corrosion cracking (SCC) has occurred in boiling water reactor (BWR) reactor head closure studs, particularly metal-plated studs. The approved lubricants used have proven to be effective in preventing seized studs or nuts. The reactor head closure studs are not metal plated. With the lack of metal plating and preventive use of approved lubricants, the Reactor Head Closure Studs Program has been effective in reducing the probability of SCC of the reactor head closure studs.

UFSAR Supplement. In LRA Section A.1.6, the applicant provided the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 Boiling Water Reactor Control Rod Drive Return Line Nozzle Program

Summary of Technical Information in the Application. The applicant's BWR Control Rod Drive Return Line Nozzle Program is described in LRA Section B.2.1.9, "Boiling Water Reactor Control Rod Drive Return Line Nozzle Program." In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle."

In the LRA, the applicant stated that the BWR Control Rod Drive Return Line Nozzle Program includes (1) an inservice inspection in accordance with the ASME Code Section XI Subsection IWB. This inspection requirement is implemented by the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, and (2) system modifications to mitigate cracking. The CRD return lines have been modified to meet the recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." The applicant stated that the CRD return lines now return to the reactor water cleanup system piping, the CRD return line reactor vessel nozzle piping has been removed, and the reactor vessel nozzles have been capped.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the

AMP described in the GALL Report, except for the staff issue described below that was resolved with a docketed response from the applicant.

The staff questioned why Units 2 and 3 perform an enhanced visual test (EVT)-1 of the inner radius instead of the Code-specified volumetric exam. The applicant stated, as documented in the staff's audit and review report, that the nozzle-to-vessel weld and inner radius are inspected in accordance with ASME Code Section XI, ISI Program, Subsection IWB, Category B-D requirements. Units 2 and 3 perform an EVT-1 of the inner radius instead of the Code-specified volumetric exam, as approved by Requests for Relief 2-ISI-16 and 3-ISI-14. The applicant indicated that an ultrasonic (UT) exam of both the nozzle-to-vessel weld and the inner radius is currently performed for Unit 1. Relief requests will not extend into the period of extended operation. The staff found the applicant's response regarding the current inspections performed for all three BFN units acceptable.

In the LRA, the applicant stated that system modifications to mitigate cracking are in progress. The CRD return lines have been modified to meet the recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive (CRD) Return Line Nozzle Cracking." The CRD return lines now return to the reactor water cleanup system piping. The CRD return line reactor vessel nozzle piping has been removed, and the reactor vessel nozzles have been capped. The staff noted that the capped CRD return line nozzles are not subject to cyclic loads from thermal stratification and striping. Therefore, they are not susceptible to cracking due to cyclic loading and do not impact AMR review. The staff found the evaluation acceptable.

Based on its review, the staff concluded that the applicant's Boiling Water Reactor Control Rod Drive Return Line Nozzle Program provides reasonable assurance of management of inservice inspection and implementation of preventive measures to mitigate cracking. The staff found this AMP acceptable. It conforms to the recommended program description, program elements, and acceptance criteria for the Boraflex monitoring program, as discussed in GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle Program."

<u>Operating Experience</u>. After implementation of the recommendations of NUREG-0619, BFN has operated for over twenty years with no significant CRD return line reactor vessel nozzle issues. The plant-specific operating experience and staff evaluation are shown in SER Section 3.1.2.3.10.

<u>UFSAR Supplement</u>. In LRA Section A.1.9, the applicant provided the UFSAR supplement for the BWR Control Rod Drive Return Line Nozzle Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 Aboveground Carbon Steel Tanks Program

Summary of Technical Information in the Application. The applicant's Aboveground Carbon Steel Tanks Program is described in LRA Section B.2.1.26, "Aboveground Carbon Steel Tanks Program." In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.M29, "Aboveground Carbon Steel Tanks Program."

In the LRA, the applicant stated that the program includes preventive measures to mitigate corrosion by protecting the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice. The flat-bottomed condensate storage tanks sit on beds of compacted sulfur-free oiled sand. The applicant also stated that it condition monitors for degradation by performing periodic inspections in accordance with the 10 CFR 50.65 Maintenance Rule Program. The applicant stated that activities to ensure that significant degradation in inaccessible tank bottoms is not occurring by performing a one-time inspection. A one-time inspection, in accordance with the One-Time Inspection Program (B.2.1.29), will be performed prior to entering the period of extended operation and will consist of thickness measurements of flat-bottomed tanks' bottom surface.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, except for the staff issue described below in subsection "UFSAR Supplement" that was resolved with a docketed response from the applicant.

Operating Experience. Some external corrosion problems have been reported on carbon steel tanks. Corrective actions have been implemented prior to loss of intended function.

UFSAR Supplement. In LRA Section A.1.23, the applicant provided the UFSAR supplement for the Aboveground Carbon Steel Tanks Program. The staff reviewed this section and determined that the information in the UFSAR supplement does not identify a one-time inspection in accordance with the One-Time Inspection Program to take thickness measurements of flat-bottomed tanks' bottom surface prior to entering the period of extended operation. This is identified as an element of the program in LRA Section B.2.1.26. Therefore, the staff could not confirm that the UFSAR supplement 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). The staff requested that the applicant provide additional information to resolve this issue. The staff followed this request for additional information in a follow up call with the applicant on April 7, 2005.

In its response, by letter May 25, 2005, the applicant confirmed the following, which resolves the staff issue:

> The One-Time Inspection Program (B.2.1.29) has been revised to specifically identify ultrasonic thickness measurements of the fuel oil storage tank bottom surfaces to ensure that significant degradation is not occurring. To implement this change, the "Program Description" section of LRA Appendix B.2.1.29, One-Time Inspection Program, has been revised to include the following item: "thickness measurements of tank bottoms to ensure that significant degradation is not occurring for those tanks

specified in the Fuel Oil Chemistry Program (B.2.1.27) and the Aboveground Carbon Steel Tanks Program (B.2.1.26)." The staff considers the issue resolved.

Conclusion. On the basis of its review and audit of the applicant's program, and the RAI response that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report, the staff concluded that the applicant 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 One-Time Inspection Program

Summary of Technical Information in the Application. The applicant's One-Time Inspection Program is described in LRA Section B.2.1.29, "One-Time Inspection Program." In the LRA, the applicant stated that this is a new program. This program is consistent with GALL AMP XI.M32, "One-Time Inspection."

In the LRA, the applicant stated that the One-Time Inspection Program will include measures to verify that unacceptable degradation of any reactor system component is not occurring; thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation.

LRA Section B.2.1.29 states that the elements of the One-Time Inspection Program will include:

- Determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience.
- Identification of the inspection locations in the SSCs based on the aging effect.
- Determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined. Nondestructive techniques will generally be used; however, in some circumstances (e.g.,small bore RCPB), destructive testing will be utilized if samples become available.
- Evaluation of the need for follow-up examinations to monitor the progression of any aging degradation. When one-time inspections fail to meet the established acceptance criteria, the Corrective Action Program will be used to schedule, track, and trend appropriate corrective actions and follow-up inspections.

LRA Section B.2.1.29 states that the One-Time Inspection Program will include the one-time inspections of SSCs that are identified generally in LRA Chapter 3.0 and in an AMR, such as:

- reactor coolant pressure boundary piping, valves, tubing, restricting orifices, and fittings less than 4-inch nominal pipe size (NPS 4) exposed to reactor coolant for loss of material and cracking
- ventilation duct work for loss of material and elastomer degradation/deterioration

- flexible connections for loss of material, cracking, and elastomer degradation/deterioration
- heat exchangers for loss of material, cracking, and biofouling
- various fittings, piping, valves, pumps, strainers, tanks, traps, tubing, expansion joints, fan housings, fire dampers, and heaters for loss of material cracking, and biofouling.

The One-Time Inspection Program will be completed before the end of the current operating license term. The schedule of the inspection will be completed in a way that minimizes its impact on plant operations; however, the inspection will not be scheduled so early in the current operating license term that will preclude questions on potential aging effects that may surface at the end of the current licensing period.

The applicant, in evaluating the AMP, stated that implementation of the One-Time Inspection Program will provide reasonable assurance that the aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

Operating Experience. The One-Time Inspection Program is new. Therefore, no programmatic operating experience is available.

UFSAR Supplement. In LRA Section A.1.26, the applicant provided the UFSAR supplement for the One-Time Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Selective Leaching of Materials Program

Summary of Technical Information in the Application. The applicant’s Selective Leaching of Materials Program is described in LRA Section B.2.1.30, “Selective Leaching of Materials Program.” In the LRA, the applicant stated that this is a new program. This program is consistent with GALL AMP XI.M33, “Selective Leaching of Materials.”

The Selective Leaching of Materials Program consists of visual inspections and hardness measurements on selected components susceptible to selective leaching. The materials of construction for these components may include cast iron, brass, bronze, or aluminum bronze. These components may be exposed to a raw water, treated water, or ground water environment. The Selective Leaching of Materials Program will perform one-time visual inspections and hardness measurements of representative components from those components identified in this LRA's AMR results. The Selective Leaching of Materials Program will be completed prior to entering the period of extended operation. The selection, inspection, and measurement techniques will be consistent with industry practice at the time of implementation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

Operating Experience. In the LRA Section B.2.1.30 the applicant evaluated the program element operating experience and stated that the Selective Leaching of Materials Program is a new program. No operating experience is available.

UFSAR Supplement. In LRA Section A.1.27, the applicant provided the UFSAR supplement for the Selective Leaching of Materials Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application**.** The applicant's Buried Piping and Tanks Inspection Program is described in LRA Section B.2.1.31, "Buried Piping and Tanks Inspection Program." In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.M34, "Buried Pipes and Tanks Inspection."

There are no buried tanks identified within the scope of license renewal. The Buried Piping and Tanks Inspection Program includes (1) preventive measures to mitigate corrosion by applying external coatings and wrappings in accordance with standard industry practices, and (2) condition monitoring to manage the effects of corrosion. The applicant stated that buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65 Maintenance Rule Program. The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, signs of environmental degradation, signs of leakage, and appreciable settlement between piping segments.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, except for the staff issue, described below, that concerned inspection of buried piping and that was resolved with a docketed response from the applicant.

The staff noted that the applicant relied solely on opportunistic inspections to check buried piping. If there were not any opportunistic inspections, the buried pipe would not be inspected. Therefore, the staff requested that the applicant agree to inspect the buried piping within 10 years after entering the period of extended operation, unless conclusive opportunistic inspections that provide a representative sample have occurred within this 10-year period. Before the tenth year, BFN should 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 systems from degradation. If it is found that sufficient inspections have not occurred to draw a conclusion regarding the underground coatings, BFN should conduct a focused inspection to allow that conclusion to be reached. The staff followed this request for additional information in a follow up call with the applicant on April 7, 2005.

In its response dated May 25, 2005, the applicant clarified the staff issue as follows:

> Buried piping within the scope of the Buried Piping and Tanks Program will be inspected when they are excavated for maintenance or when those components are exposed for any reason. BFN will perform an inspection of buried piping within ten years after entering the period of extended operation, unless an opportunistic inspection has occurred within this ten-year period. Before the tenth year, BFN 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, BFN will conduct a focused inspection to allow that conclusion to be reached. Sections A.1.28 and B.2.1.31 are modified as described below to implement this change: Paragraph (b) of LRA Appendix A.1.28, Buried Piping and Tanks Inspection Program, and paragraph (b) of the "Program Description" section of Appendix B.2.1.31, Buried Piping and Tanks Inspection Program have been revised to include the following statement: "Before the tenth year of extended operation, BFN 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, BFN will conduct a focused inspection to allow that conclusion to be reached.

Operating Experience. Review of the operating experience identified no concerns relating to the corrosion of external surfaces of buried piping or components. Several instances of buried piping replacement were identified resulting from internal corrosion or microbiological fouling or degradation. There are no buried tanks that are within the scope of license renewal.

UFSAR Supplement. In LRA Section A.1.28, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement net the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 10 CFR 50 Appendix J Program

Summary of Technical Information in the Application. The applicant's 10 CFR 50 Appendix J Program is described in LRA Section B.2.1.34, "10 CFR 50 Appendix J Program." In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.S4, "10 CFR Part 50, Appendix J."

The 10 CFR 50 Appendix J Program monitors leakage rates through the containment pressure boundary (including the drywell and torus, penetrations, fittings, and other access openings) in order to detect degradation of the primary containment pressure boundary. Seals, gaskets, and bolted connections are also monitored. Type A and Type B containment leak-rate tests are performed in accordance with the regulations in 10 CFR 50 Appendix J Option B; and the guidance provided in RG 1.163, "Performance-Based Containment Leak-Testing Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J." The 10 CFR 50 Appendix J Program requirements are mandated by Technical Specification (TS) 5.5.12, Primary Containment Leakage Rate Testing Program. Additional requirements for testing the containment are mandated by the following TS surveillance requirements: SR 3.6.1.1.1, SR 3.6.1.2.1, SR 3.6.1.3.10, and SR 3.6.1.3.11.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BFN audit and review report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

Operating Experience. In LRA Section B.2.1.34, the applicant evaluated the program element operating experience and stated that testing in accordance with 10 CFR 50 Appendix J has been effective in monitoring the pressure integrity of the primary containment boundaries industry-wide and at BFN. The staff concurred with the applicant's evaluation.

UFSAR Supplement. In LRA Section A.1.31, the applicant provided the UFSAR supplement for the 10 CFR 50 Appendix J Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant identified that the following AMPs were, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (B.2.1.2)
- Chemistry Control Program (B.2.1.5)
- Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program (B.2.1.7)
- Boiling Water Reactor Feedwater Nozzle Program (B.2.1.8)
- Boiling Water Reactor Stress Corrosion Cracking Program (B.2.1.10)
- Boiling Water Reactor Penetrations Program (B.2.1.11)
- Boiling Water Reactor Vessel Internals Program (B.2.1.12)
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program (B.2.1.14)
- Flow-accelerated Corrosion Program (B.2.1.15)
- Bolting Integrity Program (B.2.1.16)
- Open-cycle Cooling Water System Program (B.2.1.17)
- Closed-cycle Cooling Water System Program (B.2.1.18)
- Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.1.20)
- Compressed Air Monitoring Program (B.2.1.21)
- BWR Reactor Water Cleanup System Program (B.2.1.22)
- Fire Protection Program (B.2.1.23)
- Fire Water System Program (B.2.1.24)
- Fuel Oil Chemistry Program (B.2.1.27)
- Reactor Vessel Surveillance Program (B.2.1.28)
- ASME Section XI Subsection IWE Program (B.2.1.32)

- ASME Section XI Subsection IWF Program (B.2.1.33)
- Masonry Wall Program (B.2.1.35)
- Structures Monitoring Program (B.2.1.36)
- Inspection of Water-control Structures Program (B.2.1.37)
- Environmental Qualification Program (B.3.1)
- Fatigue Monitoring Program (B.3.2)

For AMPs that the applicant claimed are consistent with the GALL Report, with exceptions or enhancements, the staff performed an audit to confirm that those programs were indeed consistent. The staff also reviewed the exceptions and enhancements to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audit and reviews are documented in the following sections.

3.0.3.2.1 Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

Summary of Technical Information in the Application. The applicant's Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is described in LRA Section B.2.1.2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with exception, with GALL AMP XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

In the LRA, the applicant stated that the Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program will provide reasonable assurance that the intended functions of the neutron monitoring local power range monitor (LPRM) circuits exposed to adverse, localized environments caused by heat, radiation, and moisture can be maintained consistent with the CLB through the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with exceptions, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP bases documents against GALL AMP XI.E2 for consistency.

The staff noted that the LRA credits the EQ Program for managing aging effects for radiation monitoring system cables within the scope of license renewal. The EQ Program covers certain electrical components that are important to safety and could be exposed to harsh environment accident conditions. Since portions of the radiation monitoring cables are not exposed to a harsh environment, the staff inquired in RAI 2.5-2, below, whether all radiation monitoring cables within the scope of license renewal, located both inside and outside the containment, are covered by the EQ Program. The applicant stated, as documented in the staff's audit and review report, that all high-range radiation monitoring cables are included in the EQ Program, regardless of their location, in mild or harsh areas of the plant. The staff found the applicant's response acceptable on the basis that all of the high-range radiation monitoring cables are included in the EQ Program.

The staff's review of LRA Section B.2.1.2 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

During the audit, the staff also noted that the applicant's AMP is limited to managing the neutron monitoring local power range monitoring circuits. Not included in the scope of Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program are nuclear instrumentation cables used in circuits for the SRM, intermediate range monitor (IRM), average power range monitor (APRM), rod block monitor (RBM), and traversing in-core probe (TIP). The staff considers the IRM system to be safety-related (SR) at all BWRs and the IRM is part of the plant's TSs. The staff pursued this issue with the applicant and requested additional clarifications in RAI 2.5-2, see SER Section 2.5.1.2

Based on its response and additional discussions with the staff, the applicant concurred that the IRM instrumentation circuit cables should be within the scope of license renewal because they are part of the TS. Because of this inclusion, the applicant confirmed that their aging effects should be managed by the Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program. The applicant also agreed that other accessible neutron monitoring subsystem cables and connections will be managed by the Accessible Non-EQ Cables and Connections Inspection Program. This inclusion impacts the scope of the two AMP elements "Program Description" and "NUREG-1801 Consistency." These changes have been added to the SER Appendix A commitment table, and the applicant will modify the UFSAR supplement to reflect these changes. The details of the staff evaluation on RAI 2.5-2 are shown in SER Section 2.5.1.2.

In LRA Section B.2.1.2, the applicant stated an exception to GALL AMP XI.E2. The staff evaluation of the affected GALL elements (Parameters Monitored/Inspected and Detection of Aging Effects) for the acceptability of the exception is as follows:

<u>Exception</u> - In LRA Section B.2.1.2, the applicant takes an exception to GALL AMP XI.E2 and states that it performs a calibration procedure that implements TS requirements. The procedure is not a normal loop calibration. The procedure utilizes actual detector signals during normal operation for calibration inputs. This exception impacts the following program elements, which are evaluated as follows.

<u>Parameters Monitored/Inspected (Element 3)</u> - The parameters monitored are determined from the plant TSs and are specific to the instrumentation loop being calibrated, as documented in the surveillance test procedure. The applicant in evaluating the element stated that this program will monitor parameters that are required by TSs and are specific to the LPRM cable system being calibrated.

This program will monitor parameters that are required by TSs and are specific to the LPRM cable system being calibrated. In evaluating the exception regarding Parameters Monitored/Inspected, the applicant stated, as documented in the staff's audit and review report, that the applicant performs a specific calibration procedure as determined from plant TSs on LPRM circuits. The applicant stated that cables are part of the calibration procedure since the detector is in service when the calibration is performed. In this program, review of routine calibration results by appropriate personnel provide sufficient indication of the need for corrective actions by monitoring key parameters related to LPRM cable system performance. The normal calibration frequency specified in BFN TSs provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function.

The staff found that this exception acceptable in that it will not adversely impact the ability of the AMP to manage the affects of aging since the only difference between the applicant's program and GALL AMP XI.E2 is that the applicant utilizes actual detector signals during operation to calibrate the LPRM. The parameters monitored in the applicant's program are determined from the plant TSs and, therefore, the staff found this exception to be acceptable for the program element.

<u>Detection of Aging Effects (Element 4)</u> - 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. The normal calibration frequency specified in the plant TSs provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function. The first tests for license renewal are to be completed before the period of extended operation.

In evaluating the exception regarding Detection of Aging Effects, the applicant stated that routine calibration results will provide adequate and timely indication of the need for corrective actions by monitoring key parameters related to LPRM cable system performance. The normal calibration frequency specified in TSs provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function. Calibrations will continue through the period of extended operation at the required frequency as specified in the TSs.

As discussed above, in response to the staff's inquiry regarding the difference between the applicant's calibration procedure and that specified in GALL AMP XI.E2, the applicant stated that it performs a specific calibration procedure as determined from plant TSs on LPRM circuits. The normal calibration frequency specified in BFN TSs provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function.

The staff found that this exception will not adversely impact the ability of this AMP to manage the effects of aging since the only difference between the applicant's program and GALL AMP XI.E2 is that the applicant utilizes actual detector signals during operation to calibrate the LPRM and does not perform a loop calibration. The normal calibration frequency specified in the plant TSs provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function, and the first tests for license renewal will be completed before the period of extended operation. Therefore, the staff found this exception to be acceptable.

<u>Operating Experience</u>. In LRA Section B.2.1.2, the applicant stated that industry operating experience was incorporated into the license renewal process through a review of industry documents to identify aging effects and mechanisms that could challenge the intended function of components, systems and structures within the scope of this program. Review of plant-specific operating experience was also performed to identify aging effects experienced.

This review involved electronic database searches of plant information including problem evaluation reports, staff communications, RAIs, and WOs. As a result, no new aging effects were identified.

During the concurred audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

UFSAR Supplement. In LRA Section A.1.2, the applicant provided the UFSAR supplement for the Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Chemistry Control Program

Summary of Technical Information in the Application. The applicant's Chemistry Control Program is described in LRA Section B.2.1.5, "Chemistry Control Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with exceptions and an enhancement, with GALL AMP XI.M2, "Water Chemistry."

The purpose of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. This objective is achieved by periodic monitoring, control and mitigation of known detrimental contaminants in order to ensure that their concentrations remain below the levels known to result in corrosion and stress corrosion crack initiation and growth. The monitoring is consistent with the EPRI guidelines for BWR reactor water chemistry, condensate and feedwater, cooling water for CRDs, and other systems such as spent fuel pool water. In addition, the applicant has established an AMP consistent with GALL AMP XI.M2 "Water Chemistry."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The staff reviewed the two exceptions and one enhancement and the applicant's justifications to determine whether the AMP, with the exceptions and enhancement, remains adequate to manage the aging effects for which it is credited as follows.

Exception 1. In LRA Appendix B, the applicant stated that the GALL Report recommends that water chemistry be controlled in accordance with Boiling Water Reactor Vessel Internals Project (BWRVIP)-29. BWRVIP-29 references the 1993 revision of EPRI Report TR-103515, "BWR Water Chemistry Guidelines." The Chemistry Control Program is based on BWRVIP-79 EPRI Report TR-103515-R2, which is the 2000 Revision of "BWR Water Chemistry Guidelines."

This exception affects the program element, "Scope of Program," (Element 1) which is described as follows:

> The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (Pressurized Water Reactors (PWRs) only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or crack initiation and growth. Water chemistry control is in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs; EPRI TR-105714, Rev. 3, for primary water chemistry in pressurized water reactors (PWRs); EPRI TR-102134, Rev. 3, for secondary water chemistry in PWRs; or later revisions or updates of these reports as approved by the staff.

The applicant evaluated the exception applicable to the program element. The applicant stated that EPRI periodically updates the water chemistry guidelines, as new information becomes available. EPRI TR-103515-R2 incorporates new information to develop proactive plant-specific water chemistry programs to minimize intergranular stress corrosion cracking (IGSCC). In the "License Renewal Safety Evaluation Report for the Peach Bottom Atomic Power Station, Units 2 and 3" (ML030370189), the staff found EPRI TR-103515-R2 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience confirms the effectiveness of the reactor coolant system (RCS) chemistry program. The BFN units are similar to the Peach Bottom units. Therefore the staff conclusion reached for Peach Bottom is applicable to BFN.

In evaluating the exception, the staff stated that the difference between the two revisions is due to the 2000 revision representing a more up-to-date program. It incorporates new information, which forms the basis of the proactive, plant-specific water chemistry procedures, which will minimize IGSCC and will provide information on water chemistry that was not available when the 1993 revision was developed. In the description of the scope of the program, the GALL Report states that revisions or updates of the currently existing reports are acceptable as approved by the staff. This applies to the 2000 revision, which was approved previously by the staff for one of the license renewal plants; therefore, the staff finds that using the 2000 revision of the EPRI BWR Water Chemistry Guidelines instead of the earlier 1993 revision will not negatively impact the 10 elements of the applicant's Chemistry Control Program described in the LRA.

Exception 2. In LRA Appendix B, the applicant stated that the GALL Report indicates that hydrogen peroxide is monitored to mitigate degradation of structural materials. The applicant takes an exception that the Chemistry Control Program does not monitor for hydrogen peroxide because the rapid decomposition of hydrogen peroxide makes reliable data exceptionally difficult to obtain and EPRI TR-103515-R2 Section 4.3.3, "Water Chemistry Guidelines for Power Operation," does not address monitoring for hydrogen peroxide.

This exception affects the program elements, “Parameters Monitored or Inspected” (Element 3) and “Confirmation Process,” (Element 8), which are described as follows:

> Parameters Monitored - The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemistry integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommends that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.
>
> Confirmation Process - Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants such as chlorides, fluorides, sulfates, dissolved oxygen, and hydrogen peroxide to within the acceptable ranges. As discussed in the appendix to this report, the staff finds it acceptable to use the requirements of 10 CFR Part 50, Appendix B, in addressing the confirmation process.

The staff in evaluating the exceptions stated that monitoring of hydrogen peroxide is not required by any version of the EPRI BWR chemistry guidelines. Although there is a chemical method for measuring hydrogen peroxide, chemical reactions occurring in sample lines result in peroxide destruction before it reaches the sampling point. Obtaining meaningful results is, therefore, very difficult and not a very practical proposition. The procedure becomes even less accurate with noble metals application, which is being currently practiced at the plant, due to their catalytic effect on the hydrogen-oxygen reaction. However, the applicant stated that, if necessary, the concentration of hydrogen peroxide can be estimated at various locations by predictive radiolysis modeling. This method is acceptable to the staff, because it could provide needed information.

The description of the confirmation process in the GALL Report includes a requirement for monitoring hydrogen peroxide as one of the parameters for confirming corrective actions. For the same reasons as in scope of the program element, the staff finds it justifiable not to monitor hydrogen peroxide for confirmation purposes. The staff found the exceptions acceptable.

Enhancement 1. The Chemistry Control Program procedure is written to address all three units; however, Unit 1 must implement the latest revision to EPRI TR-103515-R2 guidelines prior to the period of extended operation. This affects the program element, "Scope of Program," (Element 1), as described below.

> The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or crack initiation and growth. Water chemistry control is in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs; EPRI TR-105714, Rev. 3, for primary water chemistry in PWRs; EPRI TR-102134, Rev. 3, for secondary water chemistry in PWRs; or later revisions or updates of these reports as approved by the staff.

In evaluating the element, the applicant stated that, with the implementation of this enhancement and with the exceptions noted above, the Chemistry Control Program will be consistent with the affected program element for all three units.

In evaluating the element, the enhancement stated that in order to make the Chemistry Control Program applicable to all three units in the Browns Ferry plant, the Revision 2000 of the EPRI BWR Chemistry Guidelines has to be implemented in Unit 1. This will make the Chemistry Control program identical for all three units. The staff finds this enhancement acceptable.

Operating Experience. In evaluating the BFN operating experience, the applicant stated that for this program element the EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use in the industry. The specific examples of BWR industry operating experience are as follows:

- IGSCC has occurred in small and large-diameter BWR piping made of austenitic stainless steels and nickel-based alloys.
- Significant cracking has occurred in recirculation, core spray, residual heat removal, and reactor water cleanup systems' piping welds.
- IGSCC has also occurred in a number of vessel internal components, including the core shroud, access hole cover, top guide, and core spray spargers.
- No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported.

As chemistry control guidelines were evolving in the industry, BFN experience with RCS chemistry was similar to that of the industry. Cracking due to IGSCC was found in reactor recirculation, reactor water cleanup, and jet pump instrumentation system piping.

The Chemistry Control Program is based on EPRI TR-103515-R2 (BWRVIP-79), which is the 2000 Revision of "BWR Water Chemistry Guidelines." EPRI periodically updates the water chemistry guidelines, as new information becomes available. The Chemistry Control Program has incorporated new EPRI information to develop a proactive water chemistry program to minimize IGSCC.

The applicant indicated that its operating experience with reactor chemistry was similar to that of the industry. The aging effect of the components was mainly due to cracking caused by IGSCC in reactor recirculation, reactor water cleanup, and jet pump instrumentation system piping. The applicant has indicated that as new information becomes available the Chemistry Control Program will be updated by developing proactive water chemistry procedures aiming at minimizing IGSCC.

The staff asked the applicant to provide plant-specific operating experience in staff RAI B.2.5.1-2 dated December 7, 2004, since the applicant stated in Appendix B that its experience was similar to the industry experience described above; however, the applicant did not provide plant-specific details to substantiate the similarity.

In its response, by letter January 6, 2005, the applicant stated that a review of BFN chemistry records revealed that the EPRI Action 3 criteria were not exceeded at any time during the five years considered. BFN short-term transients had no significant impact on reactor vessel and RCS components. In addition, these transients had no impact on the acceptability of the Chemistry Control Program as an effective aging management tool for the renewal term. Minor water chemistry excursions were noted. For example, minor excursions above Action Level 1 occurred during unit startups. In addition, several instances of condensate demineralizer resin leakage have occurred between 1999 and 2004 on Units 2 and 3 due to bleed-through of old septa and deficiencies in design/installation of new septa. Once the intrusions were identified, the source of resin was isolated and sulfates were returned to normal levels. Some instances of RCS sulfate concentration in Units 2 and 3 RCS exceeding Action Level 1 were observed in 2003 and 2004. There were no instances where Action Level 2 limits were exceeded. The majority of the elevated concentrations have been due to resin intrusions. The staff found the operating experience was not abnormal and was within the bounds of the industry experience and, therefore, acceptable.

UFSAR Supplement. In LRA Section A.1.5, the applicant provided the UFSAR supplement for the Chemistry Control Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program

Summary of Technical Information in the Application. The applicant's BWR Vessel Inside Diameter (ID) Attachment Welds Program is described in LRA Section B.2.1.7 "Boiling Water Reactor Vessel Inside Diameter Welds Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with the enhancement, with GALL AMP XI.M4, "BWR Vessel ID Attachment Welds."

In the LRA, the applicant stated that the BWR Vessel ID Attachment Welds Program implements the inspection and evaluation recommendations of staff-approved BWRVIP-48, "Vessel ID Attachment Weld Inspection and Evaluation Guidelines," (EPRI Report TR-108724, February 1998), and the primary water chemistry recommendations in accordance with BWRVIP-79, "BWR Water Chemistry Guidelines - 2000 Revision," (EPRI Report TR-103515-R2, February 2000) to ensure the long-term structural integrity of inside diameter attachment welds of the vessel.

The purpose of the BWR Vessel ID Attachment Welds Program is to manage the effects of crack initiation and growth due to SCC, including IGSCC, in the reactor vessel ID attachment welds. The program identifies welds and their inspection frequency, flaw evaluation, and repair or replacement requirements. The applicant stated that Section 7.11 of BFN Technical Instruction 0-TI-365, "Reactor Pressure Vessel Internals Inspection (RPVII) Units 1, 2, and 3," identifies vessel interior wall welds that are within the scope of this AMP. They include jet pump riser brace welds, core spray piping welds, and steam dryer support and feedwater (FW) bracket attachment welds that use furnace-sensitized stainless steel (E308/309 or 308L/309L) or alloy 182. The baseline and EVT-1, as well as re-inspection schedule, scope, and frequency for these welds are consistent with BWRVIP-48 recommendations. Other non-safety related (NSR) attachment welds that are inspected in accordance with the ASME Code Section XI, Examination Category B-N-2, are steam dryer support/holddown, guide rod, FW sparger, and surveillance sample holders. The applicant also stated that these examinations are coordinated with the ASME Code Section XI requirements in examination category B-N-2, which require visual examination of reactor pressure vessel (RPV) internal integral attachments.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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 the LRA, the applicant stated that the BWR Vessel ID Attachment Welds Program will be consistent with GALL AMP XI.M4 prior to the extended period of operation. The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the LRA and associated bases documents, and compared them to the recommendations for GALL AMP XI.M4 for consistency. The staff identified differences in the program elements, "Scope of Program" (Element 1), "Preventive Action" (Element (2), and "Acceptance Criteria" (Element 6), as discussed below.

> Scope of Program - In the description of AMP XI.M4, the GALL Report recommends that BWR water chemistry control be performed in accordance with BWRVIP-29, which references the 1993 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." However, the BFN water chemistry program is based on BWRVIP-79, the 2000 revision

of EPRI TR-103515-R2, which uses hydrogen water chemistry (HWC) with noble metal chemical application (NMCA) to control both detrimental impurities and crack initiation and growth. The staff found this difference acceptable, since BWRVIP-79 is the current revision to industry practice.

Detection of Aging Effects - The staff identified a difference in the program element for detection of aging effects. BWRVIP-48 guidelines recommend EVT-1 of all SR attachments and those NSR attachments identified as being susceptible to IGSCC. The recommendations in GALL AMP XI.M4 state that the EVT-1 should achieve at least 1 mil wire resolution. The applicant stated that BFN's EVT-1 technique is capable of achieving ½ mil wire resolution. Since the applicant's technique is more sensitive than the recommendation in the GALL Report, the staff found this difference acceptable.

Acceptance Criteria. The staff also noted that the applicant had not identified the use of BWRVIP-14, BWRVIP-59, and BWRVIP-60 in the program element for acceptance criteria to evaluate crack growth in stainless steel, nickel alloy, and low-alloy steel, respectively. The applicant responded that nuclear document Nuclear Engineering Design Procedure (NEDP)-23, Rev. 0, "BWR Reactor Pressure Vessel Internals Inspections (RPVII)," references BWRVIP-14, BWRVIP-59, and BWRVIP-60 for the evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively, as supporting documents. The staff found this acceptable.

Enhancement. In LRA Section B.2.1.7, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M4. The enhancement is that BWRVIP guidelines will be implemented for Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant's program consistent for all three units.

Operating Experience. In LRA Section B.2.1.7, the applicant stated in its evaluation of the program element, "Operating Experience," that the BWR Pressure Vessel ID Weld inspection program incorporates all susceptible welds. The inspections are based on operating experience, industry operating experience and various BWRVIP/EPRI Guidelines. The program schedules inspections, evaluates any flaws detected, and provides for repair or replacement as appropriate. The program, as implemented, has adequately managed the reactor vessel ID attachment welds.

The staff asked the applicant to describe the plant-specific operating experience relevant to the vessel ID attachment welds. The applicant provided, by its formal response dated October 8, 2004 and as documented in the staff's audit and review report, the following plant-specific operating experience:

- The jet pump riser brace to vessel pad welds are inspected by Technical Instruction 0-TI-365 ("Reactor Pressure Vessel Internals Inspection (RPVII) - Units 1, 2, and 3") in accordance with BWRVIP-41. The welds were baseline inspected during the 2001 refueling outage for Unit 2 and the 2002 and 2004 refueling outages for Unit 3. The applicant did not find any reportable indications and these welds will be inspected on Unit 1 prior to restart.
- The core spray piping bracket welds are inspected by 0-TI-365 in accordance with BWRVIP-18. The welds were baseline inspected during the 1999 refueling outage for

Unit 2 and the 2000 refueling outage for Unit 3. No reportable indications were found. These welds will be inspected on Unit 1 prior to restart.

- The inspection and flaw evaluation were performed in accordance with the guidelines of BWRVIP-48. Since the implementation of these guidelines, for approximately 4 years, no reportable indications were found in Units 2 and 3. The applicant stated that these guidelines will be implemented on Unit 1 prior to its restart.

In evaluating the element, staff concurred with the applicant that the continued implementation of the BWR Vessel ID Attachment Welds Program provides reasonable assurance that crack initiation and growth will be adequately managed and the intended functions of the vessel ID attachment welds will be maintained consistent with the CLB for the period of extended operation. The staff found that the applicant had adequately considered operating experience, consistent with the guidance in the GALL Report. (See SER Section 3.1.2.3.7)

<u>UFSAR Supplement</u>. In LRA Section A.1.7, the applicant provided the UFSAR supplement for the Boiling Water Reactor Vessel ID Attachment Welds Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR met the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Boiling Water Reactor Feedwater Nozzle Program

<u>Summary of Technical Information in the Application</u>.The applicant's BWR Feedwater Nozzle Program is described in LRA Section B.2.1.8 "Boiling Water Reactor Feedwater Nozzle Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with the enhancement, with GALL AMP XI.M5, "BWR Feedwater Nozzle."

In the LRA, the applicant stated that the BWR Feedwater Nozzle Program enhances the ISIs specified in ASME Code Section XI with the recommendations of General Electric Corporation (GE) report, NE-523-A71-0594, Rev.1,"Alternate BWR Feedwater Nozzle Inspection Requirements," August 1999.

The BWR Feedwater Nozzle Program manages cracking in reactor feedwater nozzles due to thermal fatigue. The program addresses BWR feedwater nozzle cracking by implementing the recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," November 1980. LRA Section B.2.1.8 describes the details of hardware modifications completed to mitigate cracking. The applicant also stated that changes to plant operating procedures for Units 2 and 3 have been implemented and include improved feedwater control. For details of the modification implemented, refer to LRA Section B.2.1.8.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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 the LRA, the applicant stated that the BWR Feedwater Nozzle Program will be consistent with GALL AMP XI.M5 with the enhancement described below. The staff reviewed the program elements contained in the AMP and associated bases documents, and compared them to the recommendations in GALL AMP XI.M5 for consistency.

The applicant credited GE report GE-NE-523-A71-0594, Revision 1, which has been approved by the staff, and is consistent with the GALL Report for managing crack initiation and growth in the feedwater nozzle.

Enhancement. In LRA Section B.2.1.8, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M5. The enhancement involves Unit 1 operating procedures upgraded to decrease the magnitude and frequency of FW temperature fluctuations. This enhancement affects the program element "Preventive Action." In evaluating the element, the applicant concluded that mitigation occurs by systems modifications, such as removal of stainless steel cladding and installation of improved spargers. The applicant stated that it is also accomplished by changes to plant operating procedures, such as improved feedwater control and rerouting of the reactor water cleanup system, to decrease the magnitude and frequency of temperature fluctuations.

The staff concurred with the applicant's evaluation and finds this enhancement acceptable. It will make the applicant's program consistent for all three units.

Operating Experience. Regarding plant-specific operating experience with cracking of feedwater nozzles, the applicant stated that cracking was discovered in the RPV feedwater nozzle cladding in 1977. Cladding removal and feedwater sparger replacement were performed for all three units (Unit 1 - 1977, Unit 2 - 1978, Unit 3 - 1979). Since this modification was made, no cracking problems have been found.

The staff concluded that implementation of the applicant's program provides reasonable assurance that cracking of feedwater nozzles is being adequately managed, such that there is no loss of intended function. During the concurred audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

In the LRA, the applicant concluded that the BWR Feedwater Nozzle Program provides reasonable assurance that cracking aging effects in the feedwater nozzles are adequately managed so that their intended functions, consistent with the CLB, are maintained during the period of extended operation. The staff found that the applicant had adequately considered the operating experience consistent with the guidance in the GALL Report.

UFSAR. In LRA Section A.1.8, the applicant provided the UFSAR supplement for the BWR Feedwater Nozzle Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 Boiling Water Reactor Stress Corrosion Cracking Program

Summary of Technical Information in the Application. The applicant's BWR SCC Program is described in LRA Section B.2.1.10, "Boiling Water Reactor Stress Corrosion Cracking Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an enhancement, with GALL AMP XI.M7, "BWR Stress Corrosion Cracking."

In the LRA, the applicant stated that the BWR SCC Program enhances the inservice inspections specified in ASME Code Section XI with the recommendations of NUREG-0313, Rev. 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," 1988; NRC GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking in BWR Austenitic Stainless Steel Piping," and its Supplement 1, February 1992; and BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," September 2000.

The purpose of BWR SCC Program is to manage IGSCC in reactor coolant pressure boundary components made of stainless steel. The comprehensive programs outlined in GL 88-01 and NUREG-0313, and in the staff-approved BWRVIP-75, have been implemented and address the mitigating measures for SCC and IGSCC in these components. Preventive methodologies include piping replacement with IGSCC-resistant stainless steel. Preventive measures have also included heat sink welding, induction heating, and mechanical stress improvement.

The ASME Code Section XI inspection and flaw evaluation methodology, enhanced by the recommendations of BWRVIP-75, is credited to detect and evaluate IGSCC. BWRVIP-75 allows for modification of the inspection scope identified in the GL 88-01 program. The ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program detects degradation, including IGSCC.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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 the LRA, the applicant stated that the BWR SCC Program is consistent with GALL AMP XI.M7. The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP and associated bases documents, and compared them to the recommendations in GALL AMP XI.M7 for consistency. The staff identified a difference in the program description, as well as in the program element for preventive action, as discussed below.

GALL AMP XI.M7 recommends that BWR water chemistry control be performed in accordance with BWRVIP-29, which references the 1993 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." The water chemistry programs are based on BWRVIP-79, which references the 2000 revision of EPRI TR-103515-R2 and uses HWC with NMCA to control both detrimental impurities and crack initiation and growth. The applicant stated in the LRA that BFN has not applied for any relief for vessel internals component weld inspections in accordance with BWRVIP-62, which allows relief for welds exposed to HWC. The staff found this difference acceptable, since BWRVIP-79 is the current revision to industry practice.

Regarding the program element for preventive action, the applicant stated, as documented in the staff's audit and review report, that induction heating stress improvement and mechanical stress improvement program have been used on various welds on both Units 2 and 3 as a remedy to IGSCC in austenitic stainless steel piping. However, the induction heating stress improvement technique was performed many years prior to the issuance of BWRVIP-61, which provides guidelines for induction heating stress improvement effectiveness. As part of the applicant's response to IE Bulletin 88-01, mechanical stress improvement program will be performed on applicable welds on Unit 1 prior to restart. The BWR SCC Program will continue during the period of extended operation and will implement the replacement and preventive measures as augmented by NUREG-0313, GL 88-01 and BWRVIP-75 guidelines, to mitigate IGSCC.

Additionally, the applicant stated that the materials in the sections of pipe exposed to fluid temperatures greater than 200°F are being replaced with 316 Stainless Steel NG grade material, which is not susceptible to IGSCC. The criteria for the design, installation, and testing associated with the replacement or removal of selected piping to limit the susceptibility to IGSCC for all three BFN units is provided in general design criteria (GDC) BFN-50-779, "Replacement of Selected Piping to Limit Susceptibility to IGSCC," and has been implemented for Units 2 and 3 by various design changes. Unit 1 is in the process of implementing similar design changes prior to its restart.

The applicant stated that detection of leaks due to IGSCC has been performed through inspection (Section XI and other augmented examinations, such as BWRVIP, NUREG-0619), monitoring of drywell leakage, and the feedwater leakage detection system.

The staff noted that the applicant has not identified the use of BWRVIP-14, BWRVIP-59, and BWRVIP-60 in the program element for acceptance criteria, to evaluate crack growth in stainless steel, nickel alloy and low-alloy steel, respectively. The applicant responded that

NEDP-23, Revision 0, “BWR Reactor Pressure Vessel Internals Inspections (RPVII),” references BWRVIP-14, BWRVIP-59, and BWRVIP-60, for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively, as supporting documents.

Since the applicant continues to use these measures in accordance with the staff-approved methodology, the staff found this acceptable.

Enhancement. In the LRA Section B.2.1.10, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M7. The BWR Stress Corrosion Cracking Program will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant’s program consistent for all three units.

Operating Experience. In the LRA, the applicant stated that, since the implementation of this program, structural integrity has been maintained by ensuring that aging effects were discovered and components repaired/replaced before the loss of their intended function. For Units 2 and 3, mitigation measures to prevent cracking or dispositions of examinations that have detected cracking include: targeted replacement of existing piping with piping fabricated with IGSCC-resistant material; utilizing a stress improvement process; increasing nondestructive examination frequency; implementing a hydrogen water chemistry program; and, application of weld overlay reinforcement. For Unit 1, BFN is replacing the majority of Class 1 SS piping, including any weld overlay reinforcement. Pre-service examinations of the replaced piping will be performed as required by ASME Code Section XI. After restart, applicable mitigation measures and nondestructive examinations will be performed in accordance with NUREG 0313, Revision 2, and GL 88-01 or the referenced BWRVIP-75 guideline.

The applicant stated that the BWR SSC Program provides reasonable assurance that SCC in stainless steel piping is adequately managed so that its intended functions, consistent with the CLB, is maintained during the period of extended operation. During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that the applicant will continue to review operating experience in the future to ensure that the effects of aging are adequately managed, consistent with the guidance in the GALL Report.

The staff reviewed and determined that the applicant should address the plant-specific experience related to SCC in the reactor vessel (RV) and reactor vessel internals (RVIs) at the BFN units. A detailed discussion of the staff's evaluation of Boiling Water Reactor Stress Corrosion Cracking Program is shown SER Section 3.1.2.3.8.

In RAI B.2.1.10-1(A), the staff requested that the applicant describe plant-specific experience related to IGSCC cracking of the stainless steel and nickel alloy components in RV and RVIs.

In its response to RAI B.2.1.10-1(A), by letter dated January 31, 2005, the applicant stated that no IGSCC had been identified in RV and its components at BFN, Units 2 and 3, with the exception of guide tube/dry tube (replaced with IGSCC-resistant material as discussed in Section 3.1.3.1.6.1 of the staff's SER on the AMR section). For BFN, Unit 1, the applicant proposed to implement improved RCS water chemistry to mitigate IGSCC. The staff reviewed the response and finds it acceptable, because implementation of the improved water chemistry

(AMP B.2.1.5), and ISI programs (AMP B.2.1.4) would enable the applicant to manage the aging effect due to IGSCC effectively during the extended period of operation.

In RAI B.2.1.10-1(B) the staff requested that the applicant submit information on the mitigation actions taken at BFN with respect to selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stress, and monitoring of water chemistry such as discussed in GALL AMP XI.M7, "BWR Stress Corrosion Cracking."

In its response to RAI B.2.1.10-1(B), by letter dated January 31, 2005, the applicant stated that mitigation efforts include selection of IGSCC-resistant materials and monitoring/control of water chemistry parameters. The criteria for the design, installation, and testing associated with the replacement or removal of selected RCS piping to limit the susceptibility to IGSCC is provided in GDC BFN-50-779, "Replacement of Selected Piping to Limit Susceptibility to IGSCC." Monitoring and control of chemistry parameters is controlled by AMP B.2.1.5. The staff finds AMP B.2.1.5 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience confirms the effectiveness of the RCS chemistry program. The staff found that the applicant's proposed mitigation strategy would ensure that the aging effect due to IGSCC in the RV and its components can be managed effectively during the extended period of operation.

In RAI B.2.1.10-1(C), the staff requested that the applicant provide information concerning whether any NMCA and HWC is applied at BFN. The staff requested that the applicant confirm the method of controlling HWC and any NMCA in the RV. The staff requested the applicant to provide details on the methods for determining the effectiveness of HWC and NMCA by using the following parameters:

(1) Electro Chemical Potential (ECP)
(2) Feedwater hydrogen flow
(3) Main steam oxygen content
(4) Hydrogen/oxygen molar ratio.

In its response to RAI B.2.1.10-1(C), by letter dated January 31, 2005, the applicant stated that BFN currently utilizes zinc addition, NMCA and HWC as part of the reactor water chemistry control program. BFN does not utilize ECP probes and, therefore, alternate means are used to monitor NMCA/HWC control. The acceptable alternate means are described in Section 5.4 of EPRI-103515-R2. These guidelines are implemented in BFN procedure CI-13.1, Chemistry Program, which specifies that the reactor water H_2/O_2 molar ratio must be greater than 4 during power operation to effectively mitigate IGSCC.

The staff agreed that implementation of HWC/NMCA should effectively mitigate IGSCC because these additions reduce the oxygen potential in RCS water. With reduced oxygen levels in the RCS water the occurrence of IGSCC is minimized. The effectiveness of HWC/NMCA can be maintained by using H_2/O_2 molar ratio of greater than 4, which is acceptable to the staff because this molar ratio provides adequate margin in maintaining hydrogen availability for the RV and RVIs. AMP recommended by the GALL Report for managing IGSCC for the RVIs is XI.M.7, "BWR Stress Corrosion Cracking."

UFSAR Supplement. In LRA Section A.1.10, the applicant provided the UFSAR supplement for the Boiling Water Reactor Stress Corrosion Cracking Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Boiling Water Reactor Penetrations Program

Summary of Technical Information in the Application. The applicant's BWR Penetrations Program is described in LRA Section B.2.1.11, "Boiling Water Reactor Penetrations Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an enhancement, with GALL AMP XI.M8, "BWR Penetrations."

In the LRA, the applicant stated that the BWR Penetrations Program enhances the inservice inspections specified in ASME Code Section XI with the recommendations of BWRVIP-27, "BWR Standby Liquid Control System/Core Plate P/SLC Inspection and Flaw Evaluation Guidelines, (EPRI TR-107286, April 1997)" and BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines, (EPRI TR-108695, March 1998)." Repair or replacement recommendations of BWRVIP-53, "Standby Liquid Control Line Repair Design Criteria, (EPRI TR-108716, March 24, 2000)" and BWRVIP-57, "Instrument Penetration Repair Design Criteria, (EPRI TR-108721, March 24, 2000)" are also implemented and are performed in accordance with ASME Code Section XI repair and replacement requirements. The program also incorporates the water chemistry recommendations of BWRVIP-79, "BWR Water Chemistry Guidelines, (EPRI TR-103515-R2, 2000)."

The purpose of the BWR Penetrations Program is to manage the effects of crack initiation and growth due to SCC or IGSCC in instrument and standby liquid control nozzle penetrations of the reactor vessel. The program contains preventive measures to mitigate SCC or IGSCC. The ASME Code Section XI inservice inspections implement guidelines of BWRVIP-49 and BWRVIP-27 to monitor the effects of cracking on the intended function of these penetrations. BWRVIP-57 for instrumentation penetrations and BWRVIP-53 for the standby liquid control line provide guidelines for repair and/or replacement as needed to maintain the ability to perform the intended function.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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 the LRA, the applicant stated that the BWR Penetrations Program is consistent with GALL AMP XI.M8. The staff reviewed the program elements (SER Section 3.0.2.1) contained in the AMP and associated bases documents, and compared them to those listed for GALL AMP XI.M8 for consistency.

The staff identified a difference in the program description, as well as in the program element for preventive action, as discussed below.

GALL AMP XI.M7 recommends that the BWR water chemistry control be performed in accordance with BWRVIP-29, which references the 1993 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." However, the water chemistry programs are based on BWRVIP-79, which references the 2000 revision of EPRI TR-103515-R2 and uses HWC with NMCA to control both detrimental impurities and crack initiation and growth. In the LRA, the applicant stated that BFN has not applied for any relief for vessel internals component weld inspections in accordance with BWRVIP-62, which allows relief for welds exposed to hydrogen water chemistry. The staff found this difference acceptable. BWRVIP-79 is the current revision to industry practice.

The staff also noted that the applicant has not identified the use of BWRVIP-14, BWRVIP-59, and BWRVIP-60 in the program element for acceptance criteria to evaluate crack growth in stainless steel, nickel alloy and low-alloy steel, respectively. The applicant responded that NEDP-23, Rev. 0, "BWR Reactor Pressure Vessel Internals Inspections (RPVII)," references BWRVIP-14, BWRVIP-59, and BWRVIP-60, for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively, as supporting documents. The staff found this acceptable.

Enhancement. In LRA Section B.2.1.11, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M8. The BWRVIP guidelines will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant's program consistent for all three units.

Operating Experience. In the LRA, the applicant stated that the BWR penetration program monitors the effects of SCC/IGSCC on the intended function of the component by detection and sizing of cracks by the ISI program. The ISI program incorporates the inspection and evaluation guidelines of BWRVIP-27 and BWRVIP-49. The BWRVIP-49 provides guidelines for instrument penetrations, and BWRVIP-27 addresses the standby liquid control (SLC) system nozzle or housing. Inspections are performed with BFN procedures that are part of the ISI program and incorporate the requirements of ASME Code Section XI, Table IWB-2500-1.

The applicant stated, as documented in the staff's audit and review report, that Units 2 and 3 have experienced no unacceptable conditions during the four years since implementation of the BWRVIP-27 and BWRVIP-49 guidelines. These inspections will be implemented on Unit 1 prior to its restart. The staff concluded that the recent operating experience provides reasonable assurance of the program's effectiveness.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that the applicant will continue to review operating experience in the future to ensure that the effects of aging are adequately managed, consistent with the guidance in the GALL Report. (See SER Section 3.1.2.3.11)

UFSAR Supplement. In LRA Section A.1.11, the applicant provided the UFSAR supplement for the BWR Penetrations Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Boiling Water Reactor Vessel Internals Program

Summary of Technical Information in the Application. The applicant's BWR Vessel Internals Program is described in LRA Section B.2.1.12, "Boiling Water Reactor Vessel Internals Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with the enhancement, with GALL AMP XI.M9, "BWR Vessel Internals."

In the LRA, the applicant stated that the purpose of BWR Vessel Internals Program is to manage the effects of crack initiation and growth due to SCC, IGSCC, or irradiation-assisted stress corrosion cracking (IASCC) in vessel internals components. The program contains preventive measures to mitigate SCC or IGSCC. The ASME boiler and pressure vessel (B&PV), Section XI, inservice inspection programs implement the BWRVIP guidelines associated with BWR vessel internal components, to monitor the effects of cracking on their intended functions.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the audit and review report. Furthermore, the staff reviewed the enhancements and their justifications to determine whether the AMP, with enhancements, remains adequate to manage the aging effects for which it is credited.

In the LRA, the applicant stated that BWR Vessel Internals Program is consistent with GALL AMP XI.M9. The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP and associated bases documents, and compared them to those listed for GALL AMP XI.M9 for consistency.

In accordance with NEDP-23, Revision 0, “BWR Reactor Pressure Vessel Internals Inspections (RPVII),” the applicant stated that the staff-approved BWRVIP documents identified in the GALL Report for this AMP are applicable to all units.

The staff identified a difference in the program description, as well as in the program element for preventive action, as discussed below.

The GALL AMP XI.M8 recommends that BWR water chemistry control be performed in accordance with BWRVIP-29, which references the 1993 revision of EPRI TR-103515, “BWR Water Chemistry Guidelines.” However, the BFN water chemistry programs are based on BWRVIP-79, which references the 2000 revision of EPRI TR-103515-R2 and uses HWC with NMCA to control both the detrimental impurities and crack initiation and growth. In the LRA, the applicant stated that BFN has not applied for any relief for vessel internals component weld inspections in accordance with BWRVIP-62, which allows relief for welds exposed to hydrogen water chemistry. The staff found this difference acceptable, since BWRVIP-79 is the current revision to industry practice.

The staff noted that the applicant will utilize BWRVIP-76 (which supersedes BWRVIP-07 and BWRVIP-63) for core shroud inspection and flaw evaluation guidelines during the extended period of operation.

The applicant stated, as documented in the staff’s audit and review report, that BFN committed to the use of BWRVIP documents (transmittal of revised BWRVIP commitment letter to the staff, dated June 2, 1997, RIMS R12 970612 789) and that the commitment to use BWRVIP documents includes evaluating the SER (for BWRVIP documents), and completing the applicable SER action items. The staff found this acceptable since the applicant will use the results of the staff review in implementing BWRVIP-76.

The staff requested a clarification pertaining to the utilization of BWRVIP-44 and BWRVIP-45 as part of the vessel internals AMP.

The applicant also stated that, as documented in the staff’s audit and review report, even though BWRVIP-44 and BWRVIP-45 are not specifically mentioned in BWRVIP-94 or NEDP-23 (which implements BWRVIP-94), the applicant previously committed to the use of BWRVIP documents (in revised BWRVIP Commitment Letter to the staff, dated June 2, 1997, RIMS R12 970612 789). Should weld repair of nickel-based alloys be needed, the applicant would follow the guidelines of BWRVIP-44 and BWRVIP-45 as stated in NEDP-23. The staff found this acceptable since the applicant is committed to utilization of BWRVIP-44 and BWRVIP-45, if the need arises. The staff found this acceptable, and the commitment is incorporated into SER Appendix A.

The staff noted that the applicant is taking a deviation to BWRVIP-18 on two specific items: i) pertaining to Unit 3 core spray repair design and, ii) BWRVIP- 41 on Unit 3 jet pump #5 repair design. The applicant addressed this issue in its responses dated January 31, 2005, and May 25, 2005, to the staff RAI B.2.1.12, and the details and staff disposition of the issue is shown in SER Section 3.1.2.2.7. The staff, in a follow-up call on March 29, 2005, inquired whether the applicant planned to take any exceptions to the implementation of BWRVIP inspection guidelines as a part of the AMP for the reactor vessel internals. If so, the applicant must submit the exceptions (including the exceptions that were taken on BWRVIP-18 and BWRVIP-41) to the staff for review and approval no later than two years prior to the commencement of the extended period of operation. The applicant in its response dated May 25, 2005, confirmed that it currently has not identified any exception to the BWRVIP guidelines. Hence the staff considered this RAI resolved.

Enhancement. In LRA Section B.2.1.12, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M9. The BWRVIP guidelines will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant's program consistent for all three units.

Operating Experience. In the LRA, the applicant stated that extensive cracking has been observed in core shrouds at both horizontal and vertical welds (GL 94-03, NRC IN 97-17). It has affected shrouds fabricated from Type 304 and Type 304L SS, which is generally considered to be more resistant to SCC. Weld regions are most susceptible, although it is not clear whether this is due to sensitization and/or impurities associated with the welds, or the high residual stresses in the weld regions. This experience is reviewed in GL 94-03 and NUREG-1544. Some experiences with visual inspections are discussed in IN 94-42. Most of the BWR reactors, including BFN, have experienced cracking of RPV internal components.

The staff concluded that implementation of the applicable BWRVIP guidelines provides reasonable assurance that cracking of BWR RPV internal components is being adequately managed, such that there is no loss of intended function.

During the concurred audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

UFSAR Supplement. In LRA Section A.1.12, the applicant provided the UFSAR supplement for the BWR Vessel Internals Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program

Summary of Technical Information in the Application. The applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is described in LRA Section B.2.1.14, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancement, with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of CASS."

The applicant stated that the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program monitors the effects of loss of fracture toughness on the intended function of the component by performing supplemental examinations of CASS reactor vessel internals components. The reactor vessel internals receive a visual inspection in accordance with the ASME Code Section XI Subsection IWB, Category B-N-3 requirements.

Additional enhanced visual inspections that incorporate the requirements of the BWR Vessel Internals Program are performed to detect the effects of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS reactor vessel internals.

The enhanced visual inspections include the ability to achieve a 0.0005-inch resolution, with the conditions (e.g., lighting and surface cleanliness) of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancement and its justifications to determine whether the AMP, with enhancement, remains adequate to manage the aging effects for which it is credited.

In the LRA, the applicant stated that the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is consistent with the GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)." The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP basis document and compared them against GALL AMP XI.M13 for consistency. The staff noted a difference in the program element for the scope of the program, as discussed below.

The GALL AMP XI.M13 recommendations state that the scope of the program should specify the guidelines for identification of susceptible components determined to be limiting from the standpoint of thermal aging susceptibility (i.e., ferrite and molybdenum contents, casting process, and operating temperature) and/or neutron irradiation embrittlement (neutron fluence). Either a supplemental examination of the affected component based on the neutron fluence or a component-specific evaluation to determine its susceptibility to loss of fracture toughness is to be performed. The staff noted that the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program does not address this screening process. In response to a question from the staff, the applicant stated that the scope of the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program includes supplemental examination of all CASS reactor vessel internal components. Since screening is not used, there is no need to define a screening process. The staff found this acceptable.

The staff determined that all other program elements are consistent with GALL, with one enhancement related to the program element “Scope of Program.” The applicant stated in the LRA Appendix B that the enhancement to the Thermal Aging and Neutron Irradiation Embrittlement of CASS AMP will be implemented on Unit 1. The enhancement is scheduled for implementation prior to the period of extended operation.

Staff Evaluation. In LRA Section B.2.1.14, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M13. This AMP will be implemented on Unit 1 prior to the period of extended operation. The staff found that with the implementation of this enhancement, BFN will be consistent with the affected program element for all three units.

Operating Experience. In the LRA, the applicant stated that cracking had been detected in the reactor vessel internals at several domestic and overseas boiling water reactors. In June 1994, the BWRVIP was formed to address integrity issues arising from inservice degradation of reactor vessel internals. Since that time, the BWRVIP has published several reports that present guidelines for inspecting, evaluating, and repairing reactor vessel internals.

The staff concluded that implementation of the BWRVIP guidelines for inspecting, evaluating, and repairing reactor vessel internals provides reasonable assurance that loss of fracture toughness of CASS reactor pressure vessel internal components is being adequately managed, such that there is no loss of intended function.

In GALL AMP XI.M13, void swelling is also identified as an aging mechanism leading to loss of fracture toughness in CASS reactor vessel internals. The applicant evaluated this program element “operating experience” in section LRA B.2.1.14 on page B-48 and concluded as follows:

> The continued implementation of the Thermal Aging and Neutron Irradiation Embrittlement of CASS aging management program provides reasonable assurance that the aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The BFN Reactor Vessel Internals Program is based on research data obtained from both laboratory-aged and service-aged materials. EPRI TR-107521 addresses data gathered from liquid-metal-cooled fast breeder reactors, and how it may possibly be related to a PWR component (baffle-former bolt) that is in almost direct contact with the fuel in a PWR. Since a BWR does not have components in a similar location and thus can reasonably be expected to experience less fluence, the staff concludes that is not a concern with BFN. Past studies of void swelling by ANL, ORNL, HEDL, and GE have shown that the threshold fluence for void swelling is approximately 10^{22} n/cm^2, which is well in excess of the fluence experienced by typical boiling water reactor CASS components. Secondly, the EPRI report notes that field experience does not suggest that void swelling is a significant issue. The lowest temperature for which this phenomenon is conjectured to occur is 300 °C (572 °F), which is higher than the temperature experienced by BWR reactor vessel internals. Hence the staff concluded that void swelling is not an aging effect applicable to BFN.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

UFSAR Supplement. In LRA Section A.1.14, the applicant provided the UFSAR supplement for the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. The applicant's Flow-Accelerated Corrosion (FAC) Program is described in LRA Section B.2.1.15, "Flow-Accelerated Corrosion Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with the enhancement, with GALL AMP XI.M17, "Flow-Accelerated Corrosion Program."

In the LRA, the applicant stated that the FAC Program was developed in response to GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning." The program is based on the guidelines of EPRI NSAC-202L, "Recommendations for an Effective Flow Accelerated Corrosion Program," Revision 2. The FAC Program includes the use of an industry-accepted computer code to predict FAC in carbon steel lines containing high-energy fluids (two-phase as well as single-phase systems subject to FAC). The program includes analysis to determine critical locations, baseline inspections to determine the extent of thinning at these locations, and follow-up inspections to confirm the predictions. Repair, replacements, or re-evaluations are performed as necessary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancement and its justifications to determine whether the AMP, with enhancement, remains adequate to manage the aging effects for which it is credited.

In the LRA, the applicant stated that the FAC Program will be consistent with GALL AMP XI.M17, "Flow-accelerated Corrosion." The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP basis document and compared them to those listed for GALL AMP XI.M17 for consistency. The staff also conducted a review of implementing procedure 0-TI-140 “BFN Technical Instruction, Monitoring Program for Flow-Accelerated Corrosion,” Revision 0, 03/15/02.

Enhancement. In LRA Section B.2.1.15, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M17. The NSAC-202L-R2 recommendations will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant’s program consistent for all three units.

Operating Experience. In the LRA, the applicant stated that wall-thinning problems in single-phase systems had occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01 and INs 81-28, 92-35, and 95-11), in two-phase piping in extraction steam lines (NRC INs 89-53 and 97-84), and in moisture separator and feedwater heater drains (INs 89-53, 91-18, 93-21, and 97-84) throughout the industry.

The applicant’s experience with its FAC Program activities has shown that the program can determine susceptible locations for FAC, predict component degradation, and detect wall-thinning in components due to FAC, thus providing for timely evaluation, repair, or replacement prior to loss of intended function. When FAC problems have been identified, corrective actions have been taken to prevent recurrence. For example, extraction steam, heater drain, and heater vent line piping have experienced wall-thinning due to FAC. This piping is being replaced, primarily with FAC-resistant materials.

The staff reviewed several PERs that are included in the basis document, and concluded that implementation of the applicant’s program provides reasonable assurance that loss of material due to FAC is being adequately managed, such that there is no loss of intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the GALL Report.

UFSAR Supplement. In LRA Section A.1.14, the applicant provided the UFSAR supplement for the FAC Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Bolting Integrity Program

Summary of Technical Information in the Application. The applicant's Bolting Integrity Program is described in LRA Section B.2.1.16, "Bolting Integrity Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with exceptions, with GALL AMP XI.M18, "Bolting Integrity."

The applicant stated that the Bolting Integrity Program provides for condition monitoring of selected pressure-retaining bolted joints and external surfaces of piping and components within the scope of license renewal. The applicant claimed that the Bolting Integrity Program is consistent with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," to prevent or mitigate degradation and failure of SR bolting. According to the applicant, the Bolting Integrity Program includes the following AMPs:

- ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program for Class 1, 2, and 3 components. (B.2.1.4)
- Systems Monitoring Program for bolts not included in ASME Code Section XI, Inservice Inspection Program. (B.2.1.39)

The applicant stated that the Bolting Integrity Program is consistent with GALL XI.M18 with the following exceptions:

> Exception 1. The GALL Report indicates that the program covers all bolting within the scope of license renewal including structural bolting. The applicant stated that the Structures Monitoring Program covers aging management of structural bolting.
>
> Exception 2. The GALL Report indicates that the program covers all bolting within the scope of license renewal including bolting for Class 1 nuclear steam supply system (NSSS) component supports. The applicant stated that the ASME Code Section XI, Subsection IWF Program, covers aging management of Class 1 NSSS component support bolts at the BFN Units.

These two exceptions affect the program elements "Scope of Program " and "Detection of Aging Effects." The applicant evaluated the exceptions in LRA Appendix B and stated that structural bolting is addressed by the Structures Monitoring Program and the ASME Section XI, Subsection IWF Program. These two AMPs are considered appropriate for managing the aging of these types of bolting.

The applicant also stated that requirements that are specified in EPRI NP-5769, with the exceptions noted in NUREG-1339, will be applicable for all SR bolting at the BFN units. The applicant indicated in the LRA that EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," is used as a basis for evaluation of the structural integrity of NSR bolting. The inspection requirements that are specified in ASME Code Section XI, Subsections IWB, IWC, IWD, and EPRI NP-5769 will be used in detecting the aging effects of all SR ASME Class 1, 2, and 3 bolting, and NSSS component-support bolting. The applicant indicated that these requirements are consistent with the GALL Report.

In evaluating AMP B.2.1.16, the applicant stated that continued implementation of the Bolting Integrity Program provides reasonable assurance that the aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

This AMP is credited for managing degradation of bolting in the RCS, engineered safety feature (ESF), auxiliary, and steam and power conversion systems.

Staff Evaluation. During review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with exceptions, remains adequate to manage the aging effects for which it is credited.

For SR bolting, the GALL Report relies on staff recommendations and guidelines for a comprehensive Bolting Integrity Program delineated in NUREG-1339 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," and industry's technical basis for the program and guidelines in regard to material selection and testing, bolting preload control, ISI, plant operation and maintenance, and evaluation of structural integrity of bolted joints outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. These requirements are consistent with NUREG 1801 Section XI.M18, and staff found them acceptable. Since there are no high-strength low-alloy steel bolts (yield strength greater than 150 ksi) at the BFN units, aging effects due to SCC is not credible and can be excluded from the AMP.

With regard to NSR bolting, the applicant stated that it will comply with the aging management attributes delineated in EPRI TR-104213 including material procurement, use of approved lubricants and sealants, proper torquing, and leakage evaluations. The staff found the applicant's Bolting Integrity Program for NSR bolting consistent with the recommendations in the GALL and the standards delineated in EPRI TR-104213.

The LRA states that the Bolting Integrity Program does not include bolting for Class 1 NSSS component-support bolts. The applicant stated that there are no high-strength bolts (yield strength greater than 150 ksi) in NSSS component supports. The staff evaluated this attribute and found it acceptable.

The staff previously accepted the use of periodic ISI of closure bolting as an acceptable AMP for loss of mechanical closure integrity, since failure of the mechanical joint, as evidenced by leakage, can be attributed to loss of material, cracking of bolting materials, or loss of preload. The staff determined that periodic ASME Code Section XI ISI and plant preventive maintenance programs as described in NUREG-1339 and EPRI NP-5769 can be effectively relied upon to identify loss of closure integrity for bolted assemblies. Therefore, the applicant’s management of loss of mechanical closure integrity is adequate for managing the aging effects of loss of material, cracking, and loss of preload. The staff determined that the applicant demonstrated its compliance with all the attributes of GALL AMP XI.M18 for bolting in the RCS with exceptions. The staff reviewed these exceptions, and concluded that they do not have any technical impact on the effectiveness of managing the aforementioned aging effects of the bolts in the RCS. Therefore, the staff concluded that by implementing the Bolting Integrity Program, which is consistent with GALL, the aging effects of the bolting in the RCS will be effectively managed in a timely manner for the period of extended operation.

The staff's review of the applicant's program for managing the effects of aging on structural bolting and bolting in Class 1 NSSS component supports is provided in the discussion in the SER regarding ASME Code Section XI Subsection IWF Program and Structures Monitoring Program respectively.

Operating Experience. In evaluating the program element, the applicant stated in LRA Appendix B that the BWR fleet of plants, including BFN, has experienced bolting degradation issues. The industry and BFN has implemented a Bolting Integrity Program, which adequately detected bolting integrity issues (degradation of bolting material). The Bolting Integrity Program has been effective at detecting degradation of bolting and corrective actions have been taken prior to the loss of its intended function. BFN uses no high strength bolts (actual yield strength >150 ksi).

UFSAR Supplement. In LRA Section A.1.15, the applicant provided the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Open-Cycle Cooling Water System Program

Summary of Technical Information in the Application. The applicant's Open-Cycle Cooling Water (OCCW) System Program is described in LRA Section B.2.1.17, "Open-Cycle Cooling Water System Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancement, with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The OCCW System Program relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the OCCW system will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system.

Implementation of GL 89-13 activities provides for management of aging effects due to loss of material, fouling due to micro- or macro-organisms, and heat transfer aging effects in raw water cooling water systems. The applicant does not utilize protective coatings in any raw water systems, as addressed in IN 85-24. Therefore, protective coating failures do not apply to BFN.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the OCCW System Program and associated bases documents, and compared them to those listed for GALL AMP XI.M20 report for consistency. The staff also reviewed selected implementing procedures, including Standard Program and Process (SPP)-9.7, "Corrosion Control Program," Rev. 6, which establishes the engineering requirements, details, and strategies to control corrosion of plant systems, components, equipment and structures, and the responsibilities and methodologies utilized to identify, monitor, trend, and control corrosion.

Based on its review, the staff found that the program elements of the OCCW System Program are consistent with GALL AMP XI.M20.

Enhancement. In LRA Section B.2.1.17, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M20. GL 89-13 will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant's program consistent for all three units.

Operating Experience. In LRA Section B.2.1.17, the applicant stated that it has been implementing the guidance of GL 89-13 for approximately 10 years, and found the guidance to be effective in managing aging effects due to biofouling, corrosion, erosion, pitting, and silting in structures and components serviced by OCCW systems.

The raw water fouling and corrosion control program inspection and testing activities have detected and evaluated the presence of biofouling, corrosion, microbiologically influenced corrosion (MIC), and silting. The system and component corrective actions were implemented prior to loss of system function. The raw water fouling and corrosion control program activities adequately manage the aging effects of loss of material, cracking, pitting, flow blockage, and reduction of heat transfer in components exposed to raw cooling water.

The staff concluded that implementation of the applicant's program provides reasonable assurance that aging effects due to biofouling, corrosion, erosion, pitting, and silting in structures and components serviced by OCCW systems are being adequately managed, such that there is no loss of intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.16, the applicant provided the UFSAR supplement for the OCCW System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Closed-Cycle Cooling Water System Program

Summary of Technical Information in the Application. The applicant's Closed-Cycle Cooling Water (CCCW) System Program is described in LRA Section B.2.1.18, "Closed-Cycle Cooling Water System Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an enhancement, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System."

The CCCW System Program includes preventive measures to minimize corrosion and surveillance testing and inspection to monitor the effects of corrosion on the intended function of the component. The program relies on maintenance of system corrosion inhibitor concentrations within specified limits of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," to minimize corrosion. Surveillance testing and inspection in accordance with standards in EPRI TR-107396 for CCCW systems is performed to evaluate system and component performance. These measures will ensure that the CCCW system and components serviced by the CCCW system are performing their functions acceptably.

CCCW System Program will be enhanced to implement EPRI TR-107396 for Unit 1 prior to the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the CCCW System Program and associated bases documents, and compared them to those listed for GALL AMP XI.M21 for consistency.

The staff also reviewed the applicant's implementing procedures, including Browns Ferry Chemical Instruction CI-13.1, and "Browns Ferry Nuclear Plant Chemistry Program," Revision 17, which incorporates EPRI TR-107396, “Closed Cooling Water Chemistry Guidelines.” Appendix A of that procedure provides water quality control specifications for the reactor building closed-cooling water system, drywell outage chiller (when inservice), off-gas chiller systems, closed-building heating, generator stator cooling water, diesel generator cooling water, and control bay chiller systems. The parameter monitored, monitoring frequency, administrative goal, and action levels for corrective actions are identified for each system.

The staff’s review determined that the applicant’s CCCW systems program monitors the effects of corrosion by system chemistry sampling, chemical treatment and water chemistry trending in accordance with the Water Chemistry Program. The chemistry parameters are monitored and maintained in accordance with the BFN chemistry specifications and recommendations of EPRI TR-107396. The parameters monitored include nitrate, pH, conductivity, tolyltriazole, bacteria (aerobic and SRBs), sulfates, metals (iron, copper), ammonia, chloride, calcium, molybate, and glycol (weight percent). If parameter limits are exceeded, the chemistry control procedures require corrective action to be taken to restore parameters to within the acceptable range. Maintenance of water chemistry and corrosion inhibitor levels within the chemistry parameters mitigate loss of material, cracking, and reduction of heat transfer. In addition, regular scheduled system flow balances, pump suction and discharge pressure, heat exchanger flows, and temperatures and maintenance inspections are performed on system/components to detect, monitor, control, and minimize corrosion aging effects. The system heat exchangers are also cleaned and inspected to detect, monitor, control, and minimize corrosion aging effects that could cause a reduction of heat transfer.

Based on its review, the staff found that the program elements of the CCCW System Program are consistent with GALL AMP XI.M21.

<u>Enhancement</u>. In LRA Section B.2.1.18, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M21. EPRI TR-107396 will be implemented on Unit 1 prior to the period of extended operation. The staff found this enhancement acceptable since it will make the applicant’s program consistent for all three units.

<u>Operating Experience</u>. In the LRA, the applicant stated that industry operating experience demonstrates that the use of corrosion inhibitors in closed-cooling water systems that are monitored and maintained by chemistry activities is effective in mitigating loss of material, cracking, and reduction of heat transfer. The BFN CCCW systems have not experienced a loss of intended function of components due to corrosion product buildup or through-wall cracking of components. The CCCW systems inspection and testing have detected loss of material and corrosion product buildup. These aging effects were identified and corrected prior to loss of system functions.

The staff concluded that implementation of the applicant’s program provides reasonable assurance that loss of material, cracking, and reduction of heat transfer in CCCW systems are being adequately managed such that there is no loss of intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.17, the applicant provided the UFSAR supplement for the CCCW System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Inspection of Overhead Heavy Load and Light Load Handling Systems Program

Summary of Technical Information in the Application. The applicant's Inspection of the Overhead Heavy Load and Light Load Handling Systems Program is described in LRA Section B.2.1.20, "Inspection of Overhead Heavy Load and Light Load Handling Systems Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an exception, with GALL AMP XI.M23, "Inspection of Overhead Heavy Load (Related to Refueling) and Light Load Handling Systems."

In LRA Section B.2.1.20, the applicant stated that Inspection of the Overhead Heavy Load and Light Load Handling Systems Program includes crane inspection activities to verify the structural integrity of the crane components required to maintain the crane intended function. Visual inspections assess conditions such as loss of material due to corrosion of structural members, misalignment, flaking, side wear of rails, loose tie-down bolts, and excessive wear or deformation of monorails. Crane functional tests are periodically performed to assure the cranes capability. The effectiveness of the program is monitored in accordance with the guidance of RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the Inspection of the Overhead Heavy Load and Light Load Handling Systems Program and associated bases documents, and compared them to those listed for GALL AMP XI.M23 for consistency.

In LRA Section B.2.1.20, the applicant identified an exception to GALL AMP XI.M23 that affects GALL Report element Parameters Monitored/Inspected. Reactor building crane fatigue was evaluated as a TLAA in LRA Section 4.7.1. The disposition of the TLAA is that the analyses are valid through the period of extended operation because the 60-year 7,500-cycle estimate remains a small fraction of the 100,000 cycle design. Therefore, the applicant stated that aging management of crane fatigue is not required.

Exception. The staff evaluation of the affected GALL Report program element, “Parameters Monitored/Inspected” (Element 3), for the acceptability of the exception is as follows:

> Parameters Monitored/Inspected. The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The number and magnitude of lifts made by the crane are also reviewed.

The staff found this exception acceptable on the basis that the crane is designed for 100,000 lift-cycles, compared to the applicant’s 60-year estimate of 7,500 cycles (1.5 times 40-year estimate of 5,000 cycles), as documented in LRA Section 4.7.1. The staff found that, with evaluation of the exception discussed below, the program elements reviewed for the Inspection of the Overhead Heavy Load and Light Load Handling Systems Program are consistent with GALL AMP XI.M23.

Operating Experience. In the Inspection of the Overhead Heavy Load and Light Load Handling Systems Program basis document, the applicant stated that no incidents of failure of passive crane and hoist components due to aging have occurred at Browns Ferry. The requirements for monitoring the effectiveness of maintenance at nuclear power plants provided in 10 CFR 50.65 have been incorporated into the Maintenance Rule Program procedures.

The staff concluded that the crane inspection program activities, implemented as part of the Maintenance Rule Program, provide reasonable assurance that the intended functions of crane and hoist passive components will be maintained during the period of extended operation.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.18, the applicant provided the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 Compressed Air Monitoring Program

Summary of Technical Information in the Application. The applicant's Compressed Air Monitoring Program is described in LRA Section B.2.1.21, "Compressed Air Monitoring Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancements, with GALL AMP XI.M24, "Compressed Air Monitoring."

The Compressed Air Monitoring Program will be enhanced prior to the period of extended operation to include program and procedure upgrades that will be credited for license renewal, to ensure that the applicable aging effects are discovered and evaluated. Also, the Unit 1 control air system procedures will be updated to fully implement the compressed air monitoring program on Unit 1, prior to Unit 1 re-start from its current extended outage.

The Compressed Air Monitoring Program consists of condition monitoring (inspection and testing of the system) and preventive actions (air quality at various locations in the system is monitored to ensure that oil, water, rust, dirt, and other contaminants are kept within specified limits). The program includes inspection, monitoring, and testing of the entire system, including frequent leak testing of valves, piping, and other system components, especially those made of carbon steel, and preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits.

The Compressed Air Monitoring Program is based on GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," and the Institute of Nuclear Power Operations (INPO) Significant Operating Experience Report (SOER) 88-01, "Instrument Air System Failures." The AMP also incorporates provisions conforming to the guidance of the EPRI NP-7079, issued in 1990 to assist utilities in identifying and correcting system problems in the instrument air system and to enable them to maintain required industry safety standards. Additionally, the Compressed Air Monitoring Program will be upgraded to implement these guidelines of EPRI TR-108147, which addresses maintenance of the latest compressors and other instrument air system equipment in use, and the ASME Code operations and maintenance standards and guides (ASME Code OM-S/G-1998, Part 17), which provide additional guidance for the maintenance of the instrument air system, including recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. 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 LRA Section B.2.1.21, the applicant indicated that the Compressed Air Monitoring Program requires implementation of two enhancements to achieve consistency with GALL AMP XI.M24 for all three units.

Enhancement 1. The staff evaluation of the affected GALL Report program elements, "Preventive Actions" (Element 2) and "Detection of Aging Effects" (Element 3), for the acceptability of the enhancement is as follows:

> Preventive Actions - The system air quality is monitored and maintained in accordance with the plant owner's testing and inspection plans, which are designed to ensure that the system and equipment meet specified operability requirements. These requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME Code OM-S/G-1998, Part 17; ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147. The preventive maintenance program addresses various aspects of the inoperability of air-operated components due to corrosion and the presence of oil, water, rust, and other contaminants.
>
> Detection of Aging Effects - Guidelines in EPRI NP-7079, EPRI TR-108147, and ASME Code OM-S/G-1998, Part 17, ensure timely detection of degradation of the compressed air system function. Degradation of the piping and any equipment would become evident by observation of excessive corrosion, by the discovery of unacceptable leakage rates, and by failure of the system or any item of equipment to meet specified performance limits.

Enhancement 2. Unit 1 control air system procedures will be updated to fully implement the Compressed Air Monitoring Program on Unit 1. This enhancement is scheduled for completion prior to Unit 1 re-start from its current extended outage.

For all units, the Compressed Air Monitoring Program will be upgraded to implement the following guidelines: ASME Code OM-S/G-2000, Part 17, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants"; ANSI/ISA-S7.0.01-1996, "Quality Standard for Instrument Air"; and EPRI TR-108147, "Compressor and Instrument Air System Maintenance Guide." This enhancement is scheduled for completion prior to the start of the period of extended operation.

The staff concurred that with the implementation of these enhancements the Compressed Air Monitoring Program will be consistent with GALL AMP XI.M24 for all three units.

Operating Experience. In LRA Section B.2.1.21, the applicant stated that, through air quality testing and sampling of the compressed air systems, various contaminants such as moisture, oil, and particulates, have been identified above acceptable levels, as documented in the staff's BFN audit and review report. Appropriate corrective actions have been taken.

Potentially significant SR problems pertaining to air systems have been documented in IN 81-38, IN 87-28, IN 87-28 S1 and licensee event report (LER) 50-237/94-005-3. As a result of GL 88-14 and consideration of INPO SOER 88-01, EPRI NP-7079, and EPRI TR-108147, performance of air systems has improved significantly.

The applicant stated that GL 88-14, IN 81-38, IN 87-28, IN 87-28 S1, INPO SOER 88-01 and EPRI NP-7079 had been adequately addressed and that the control air system performance has improved significantly as a result of GL 88-14, and consideration of INPO SOER 88-01 and EPRI NP-7079. In addition, the control air leak detection program has been effective in detecting leaks and implementing repairs prior to loss of system function. The air quality sampling program effectively monitors the system for moisture, oil, and particulates. This ensures timely repairs prior to degradation to the point of loss of intended function.

The applicant also identified that the drywell control air system has a trend of moisture problems, which has required considerable attention. To address the current operating deficiencies identified in the drywell control air system, the applicant plans to convert the drywell control air to nitrogen supply on all three units. This conversion has already been initiated for Unit 1. The staff noted that this plant modification addresses a current operating problem, and is not related to any license renewal commitment.

The staff concluded that implementation of the applicant's program provides reasonable assurance that age-related degradation of compressed air systems is being adequately managed, such that there is no loss of intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.19, the applicant provided the UFSAR supplement for the Compressed Air Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 BWR Reactor Water Cleanup System Program

Summary of Technical Information in the Application. The applicant's BWR Reactor Water Cleanup System Program is described in LRA Section B.2.1.22, "BWR Reactor Water Cleanup System Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an enhancement, with GALL AMP XI.M25, "BWR Reactor Water Cleanup System Program." This program will be enhanced to implement the BWRVIP guidelines, GL 88-01, and GL 89-10 for Unit 1 prior to the period of extended operation.

The BWR Reactor Water Cleanup System Program includes inservice inspection and monitoring for reactor water cleanup (RWCU) system piping welds outboard of the second isolation valve and monitors and controls reactor water chemistry based on industry-recognized guidelines of EPRI Report TR-103515, “BWR Water Chemistry Guidelines (BWRVIP-79)," prevents, minimizes, mitigates, and reduces the susceptibility of RWCU system piping to SCC and IGSCC.

On Units 2 and 3, RWCU system piping has been replaced with piping that is resistant to IGSCC in response to GL 88-01, “NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," concerns. In addition, all actions requested in GL 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” have been completed.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation are documented in the BFN audit and review report. 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.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the BWR Reactor Water Cleanup System Program and associated bases documents, and compared them to those listed for GALL AMP XI.M25 for consistency.

The staff also reviewed selected implementing procedures, including CI-13.1, “Chemistry Program.” This instruction details specific requirements for the chemistry program. This chemical instruction establishes how the chemistry program is implemented and provides specifications to maximize long-term plant availability, minimize environmental impact, and minimize worker radiation exposure. Controlling water quality through control of ingress and cleanup system optimization limits corrosion, minimizes radioactive inventory, and minimizes radioactive releases to the environment. The requirements of this instruction apply to all aspects of the chemistry program associated with BFN and supporting facilities. This instruction defines the minimum requirements for the site and corporate chemistry programs as they apply to BFN. This includes incorporation of EPRI TR-103515, Revision 2 guidelines. In addition, HWC must be installed for mitigation of IGSCC, which will include the RWCU system for Unit 1.

The staff found that the program elements reviewed for BWR Reactor Water Cleanup System Program are consistent with GALL AMP XI.M25.

> Enhancement. In LRA Section B.2.1.22, the applicant identified one enhancement to make this AMP consistent with GALL AMP XI.M25. On Unit 1 the recommendations of GL 88-01 and NUREG-0313 will be implemented and the actions requested in GL 89-10 will be satisfactorily completed. These enhancements are scheduled for completion prior to the period of extended operation.

The staff found that with the implementation of this enhancement the BWR Reactor Water Cleanup System Program will be consistent with GALL AMP XI.M25 for all three BFN units.

Operating Experience. In LRA Section B.2.1.22, the applicant stated that IGSCC has occurred in boiling water reactor piping made of austenitic stainless steel. The comprehensive program outlined in GL 88-01 and NUREG-0313 addresses improvements in managing the elements (susceptible material, significant tensile stress, and an aggressive environment) that cause

SCC or IGSCC, and has been effective in managing IGSCC in austenitic stainless steel piping in the RWCU system.

The applicant identified that the applicant experienced IGSCC in the past with piping made of austenitic stainless steel. The following measures that have been implemented have proven effective at managing IGSCC in austenitic stainless steel piping in the RWCU system: (1) replacement of IGSCC-susceptible material with IGSCC-resistant material, (2) establishment of a HWC program, and (3) water chemistry controls in accordance with EPRI guidelines.

The staff concluded that implementation of the recommendations of GL 88-01 and NUREG-0313 and the actions requested in GL 89-10 provides reasonable assurance that cracking of austenitic stainless steel piping in the RWCU system is being adequately managed, such that there is no loss of intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.20, the applicant provided the UFSAR supplement for the BWR Reactor Water Cleanup System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Fire Protection Program

Summary of Technical Information in the Application. The applicant’s Fire Protection Program is described in LRA Section B.2.1.23, “Fire Protection Program.” In the LRA, the applicant stated that this is an existing program. This program is consistent, with exceptions and enhancement, with GALL AMP XI.M26, “Fire Protection Program.”

The applicant stated in the LRA that the Fire Protection Program manages the aging effects of loss of material, cracking, and change of material properties for plant fire protection features and components. The program manages these aging effects through the use of periodic inspections and tests. The Fire Protection Program includes fire barrier inspections and diesel-driven fire pump tests. Fire protection inspections and tests are mandated by the Fire

Protection Report (FPR) Volume 1, which is incorporated by reference into UFSAR 10.11. The FPR requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection of fire-rated doors to ensure that their operability is maintained. The FPR requires that the diesel-driven fire pump be periodically tested to ensure that the fuel supply line can perform the intended function. The FPR also includes periodic inspection and test of the carbon dioxide fire suppression system.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in its BFN audit and review report. Furthermore, the staff reviewed the exceptions and enhancement and their justifications to determine whether the AMP, with the exceptions and enhancement, remains adequate to manage the aging effects for which it is credited.

Exception 1. Personnel performing fire seal and fire door inspections are not qualified to VT-1 and VT-3 requirements.

The staff's review of LRA Section B.2.1.23 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.0.2, dated August 23, 2004, the staff questioned the exception to the GALL Report regarding the qualifications of the personnel performing the inspections of fire barriers, penetration seals, and fire doors who are not qualified to VT-1 and VT-3 requirements. In the LRA the applicant had stated that the personnel performing these inspections are trained and experienced in the fire protection requirements and that the quality of the inspections is equivalent to VT-1 and VT-3 inspections. FPR Section 9.4.11.G discussed semi-annual inspection of fire doors including a check of closers and latching mechanisms. The staff also requested justifications for specific exceptions taken to the GALL Report AMP on fire doors. The GALL Report recommends verification of door clearances to assure the door can perform in a fire and remain latched. The staff further requested additional information concerning how a visual inspection can verify proper closure of latching mechanism and asked the applicant to confirm that the frequency of this surveillance is consistent with the FPR.

Fire Protection Report Volume1 Fire Protection Systems Surveillance Requirement 9.4.11.D, CO_2 systems, mandates the CO_2 systems' requirements for demonstrating operability. This test stipulates that the system, including associated ventilation system fire dampers and fire door release mechanisms, actuates manually and automatically upon receipt of a simulated actuation signal, and verify flow from each nozzle through a puff test.

In its response, by letter September 30, 2004, the applicant stated:

> Surveillance Instruction (SI) 0-SI-4.11.G.2, Semiannual Fire Door Inspection is discussed in the AMP and is being credited as one of the BFN site specific procedures credited for the Fire Protection Aging Management Program. A SI verifies the required clearances are maintained and periodic functional tests of closing mechanisms are performed. The only exception to the GALL in the AMP for fire doors is that inspectors are not qualified to visual examination (VT-1 and VT-3) requirements.

The frequency and inspection of the fire doors is defined in the FPR and the SIs written to satisfy the requirement.

The staff reviewed the SI, acceptance criteria, including surveillance requirement 9.4.11.D, above, and plant operating experience, and concurred the program is adequate for managing the effect of aging in the fire doors. Therefore, the staff's concern discussed in RAI B.2.0.2 is resolved.

Exception 2. The FPR requires testing and inspection of the CO_2 system once every 18 months.

LRA Section B.2.1.23, Element 3 - "Parameters Monitored or Inspected" and Element 4 - "Detection of Aging Effects," takes exceptions over the inspection interval to test for the halon/carbon dioxide fire suppression system every 18 months, instead of biannually as recommended by the GALL Report.

The applicant stated that the 18-month frequency is considered sufficient to ensure system availability and operability based on the plant operating history, and that there has been no aging-related event that has adversely affected system operation. The 18-month frequency is included in the CLB.

The staff reviewed the applicant's FPR basis document, plant operating experience, and fire surveillance procedures. Because these aging effects occur over a considerable period of time, the staff concluded that the 18-month inspection interval will be sufficient to detect aging of CO_2.

Enhancement 1. The FPR and procedures will be updated to include Unit 1 as an operating rather than a shutdown unit. The Fire Protection Program will be fully implemented on Unit 1. The enhancement is scheduled for completion prior to the period of extended operation

In the LRA, the applicant stated that "with the implementation of this enhancement, BFN will be consistent with the affected program element for all three units."

Operating Experience. The applicant reported that operating experience indicates a trend of piping degradation, such as leaks, general corrosion, and biofouling. Piping is replaced as required in response to findings of the inspection and testing activities which indicate the need for corrective actions.

UFSAR Supplement. In LRA Section A.1.21, the applicant provided the UFSAR supplement for the Fire Protection Inspection program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI response, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL program are consistent with the GALL program. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation and restart of Unit 1 would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff found that the applicant had 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).

3.0.3.2.17 Fire Water System Program

Summary of Technical Information in the Application. The applicant's Fire Water System Program is described in LRA Section B2.1.24, "Fire Water System Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with the exception and enhancements, with GALL AMP XI.M27, "Fire Water System," as modified by ISG-04.

The Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. The testing assures the minimum functionality of the systems. The fire water system tests are mandated by the FPR Volume 1, which is incorporated by reference into UFSAR 10.11. The Fire Water System Program is an existing program that takes exceptions to GALL AMP XI.M27 evaluation elements, as modified by ISG-04, and requires enhancements to be consistent with other GALL AMP XI.M27 evaluation elements.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in its BFN audit and review report. Furthermore, the staff reviewed the exception and enhancements and their justifications to determine whether the AMP, with the exception and enhancements, remains adequate to manage the aging effects for which it is credited.

Exception. The applicant takes exception that water-based fire protection systems meet the inspection, testing and maintenance requirements of current NFPA standards. However, the Fire Water Program was developed using NFPA as well as other applicable industry guides and standards and the design of the water-based system generally meets the applicable NFPA standards. This exception affects the program elements, "Parameters Monitored or Inspected" (Element 3), "Monitoring and Trending" (Element 5), and "Operating Experience" (Element 10) which are discussed below.

Parameters Monitored or Inspected and Monitoring and Trending (As modified by ISG-04) - The GALL Report for this program element specifies that loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. The GALL Report recommends that the applicant perform periodic flow testing of the fire water system using the guidelines of NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection System" Chapter 13, Annexes A & D at the maximum design flow or perform wall-thickness evaluations to ensure that the system maintains its intended function. In evaluating the program elements, the applicant did not confirm that periodic flow testing is performed using the guidelines of NFPA 25 as described in the parameters monitored or inspected program element, nor monitor the results of system performance testing and trending, as specified by the current NFPA codes and standards and described in the monitoring and trending program element. However, the Fire Water System Program was developed using NFPA as well as other applicable industry guides and standards.

The applicant did not confirm that the water-based fire protection systems are inspected, tested and maintained in accordance with current NFPA standards. Neither has the applicant confirmed that the periodic water flow testing meets the requirements of NFPA 25. The staff reviewed SI 0-SI-4.11.B.1.g, "High Pressure Fire Protection System Flow Test," Revision 20, and concluded that the extent of the testing, the acceptance criteria, and the analysis of the test data outlined in the document is detailed and adequate to assess the ability of the system to perform its intended function. The staff was satisfied with the review; therefore, the staff found the exception acceptable.

Enhancement 1. In LRA Section B.2.1.24, the applicant proposed an enhancement that the FPR and procedures will be updated to include Unit 1 as an operating rather than a shutdown unit. The Fire Water System Program will be fully implemented on Unit 1. This enhancement is scheduled for completion prior to the period of extended operation. This enhancement affects the program element "Scope of Program."

In evaluating the enhancement, the staff concluded that this enhancement will bring the AMP common to all units and will be updated to bring Unit 1 to an operating status, rather than shut down. The enhancement is, hence, acceptable.

Enhancement 2. In LRA Section B.2.1.24, the applicant proposed an enhancement. BFN will perform flow tests or non-intrusive examinations (e.g., volumetric tests for wall thickness of fire protection system piping) to identify evidence of loss of material due to corrosion. The applicant stated that these inspections will be performed before entering the period of extended operation. This enhancement affects the program elements, "Parameters Monitored or Inspected" (Element 3) and "Detection of Aging Effects" (Element 4).

Parameters Monitored or Inspected - In its evaluation, the applicant stated that the Fire Water System Program monitors parameters that indicate the systems' ability to maintain pressure and allow detection of internal system corrosion conditions. The Fire Water System Program requires system and component testing and inspections as well as periodic flow testing. Wall thickness evaluations are determined by the system engineer when systems are opened for maintenance and by pressure tests/leak detection. The Fire Water System Program includes flow testing and system evaluations to ensure that the system maintains its intended function.

The staff evaluated the program element together with the ISG-04 revised criteria for the GALL AMP XI.M27 for this program element. This revised guidance 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-04 recommends either periodic flow testing of the fire water system using the guidelines of NFPA 25, at the maximum design-flow, or periodic wall-thickness evaluations to ensure that the system maintains its intended function. Based on the applicant's commitment to inspect fire water system components, the staff determined that the program element is acceptable and that it complies with ISG-04 recommendations.

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Detection of Aging Effect - The applicant, in evaluating this element, stated that the environmental and material conditions that exist on the interior surface of the below grade fire water system piping are similar to the conditions that exist within the above-grade fire water system piping. The results of the inspections of the above grade fire water system piping will be extrapolated to evaluate the condition of below-grade fire water system piping to ensure that the intended function of below-grade fire water system piping will be maintained consistent with the CLB for the period of extended operation. Repair and replacement actions are initiated as necessary. The plant-specific inspection intervals are to be determined by engineering evaluation of the fire protection piping to detect degradation prior to the loss of intended function. The purpose is to ensure that corrosion, MIC, or biofouling is managed such that the system function is maintained. With the implementation of this enhancement, BFN will be consistent with the affected program elements, except for the exception previously described for the "Parameters Monitored or Inspected" element.

Based on the above evaluation of the two program elements,. the staff found that enhancement 2 is acceptable.

Enhancement 3. In LRA Section B.2.1.24, the applicant proposed an enhancement; that BFN will perform sprinkler head inspections before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. This enhancement is scheduled for completion prior to exceeding the 50-year service life for any sprinkler. This enhancement affects the program element "Detection of Aging Effects" (Element 4).

Detection of Aging Effects - GALL AMP XI.M27 contains the criteria for the program element "Detection of Aging Effects." The applicant in evaluating this element affected stated that a sample of sprinkler heads will be inspected using the guidance of NFPA 25, 2002 Edition, Section 5.3.1.1.1. This NFPA section states that "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing.

In evaluating this program element, the staff stated that ISG-04 revised criteria for the GALL AMP XI.M27 "Detection of Aging Effects" program element recommends sprinkler head inspections before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation to ensure that signs of degradation are detected in a timely manner. Based on the revised GALL Report criteria in ISG-04, and the applicant's commitment to rely upon applicable codes and standards to develop test procedures, the staff determined enhancement 3 to be acceptable.

Operating Experience. In LRA Section B.2.1.24, the applicant stated that the fire water system parameters are monitored and tested, and that piping and component evaluations are performed to ensure that the system maintains its intended function. The BFN Fire Water System operating experience indicates a trend of piping degradation, such as leaks, general corrosion, and biofouling, etc. Piping is being replaced, as required, in accordance with corrective actions of the inspection and testing activities. The applicant also stated that the continued implementation of the Fire Water System Program provides reasonable assurance that aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

UFSAR Supplement. In LRA Section A.1.22, 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 provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Fuel Oil Chemistry Program

Summary of Technical Information in the Application. The applicant's Fuel Oil Chemistry Program is described in LRA Section B.2.1.27, "Fuel Oil Chemistry Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with two exceptions (TVA submittal dated September 14, 2006), with GALL AMP XI.M30, "Fuel Oil Chemistry Program."

In LRA Section B.2.1.27, the applicant stated that the Fuel Oil Chemistry Program consists of surveillance and maintenance procedures to mitigate corrosion, and measures to verify the effectiveness of the AMP and to confirm the absence of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the guidelines of the American Society for Testing Materials (ASTM) Standards D 1796, D 2276, and D 4057. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining of water or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. Procedures require performance of fuel oil tank bottom and multi-level sampling on a quarterly basis to detect and remove water and sediment from each tank. In addition, each 7-day diesel oil supply tank is cleaned and inspected at intervals of approximately 10 years. A one-time inspection in accordance with the One-Time Inspection Program (B.2.1.29) will be performed prior to entering the period of extended operation and will consist of thickness measurements of the 7-day diesel oil supply tanks and diesel driven fire pump fuel oil tank bottom surface.

The applicant also stated that this program provides a general description of items to be included within the scope of the program, but does not specifically identify the 7-day diesel oil supply tank as an item to be inspected.

Portions of the Fuel Oil Chemistry Program are mandated by TS 5.5.9, “Diesel Fuel Oil Testing Program,” that requires a diesel fuel oil testing program to implement required testing of the fuel oil in each 7-day fuel oil tank. The purpose of the program is to establish that the quality of the fuel oil in each 7-day fuel oil tank is within the acceptable limits specified in Table 1 of ASTM D-975-1989 when tested every 92 days; and total particulate concentration of the fuel oil in each 7-day fuel oil tank is less than 10 mg/l, when tested every 92 days in accordance with ASTM D-2276, Method A-2 or A-3.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation are documented in its BFN audit and review report. Furthermore, the staff reviewed the exception and justification to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the Fuel Oil Chemistry Program and associated bases documents, and compared them to those listed for AMP XI.M30 in the GALL Report for consistency.

In its response to RAI 7.1.19-1, by letter dated May 25, 2005, the applicant stated:

> The One-Time Inspection Program (B.2.1.29) has been revised to specifically identify ultrasonic thickness measurements of the fuel oil storage tank bottom surfaces to ensure that significant degradation is not occurring.
>
> To implement this change, the “Program Description” section of LRA Appendix B.2.1.29, One-Time Inspection Program, has been revised to include the following item:
>
> - Ultrasonic thickness measurements of tank bottoms to ensure that significant degradation is not occurring for those tanks specified in the Fuel Oil Chemistry Program (B.2.1.27) and the Aboveground Carbon Steel Tanks Program (B.2.1.26).

The staff also reviewed BFN Procedure CI-130, “Diesel Fuel and Lube Oil Monitoring Program,” and Procedure 0-SR-3.8.3.3 “Quarterly Fuel Oil Quality Determination of Unit 0 Diesel Generator's 7-Day Storage Tank Supply.”

Exception 1. In LRA Section B.2.1.27, the applicant identified an exception to GALL AMP XI.M30 that affects three program elements. The applicant does not use ASTM Standard D 2709 for guidance on the determination of water and sediment contamination in diesel fuel, as specified in GALL AMP XI.M30. The applicant does implement ASTM Standard D 1796 guidance on the determination of water and sediment contamination, which is also specified in GALL AMP XI.M30.

The staff evaluation of the affected GALL Report program elements, “Scope of Program” (Element 1), “Preventive Action” (Element 2), “Parameters Monitored or Inspected” (Element 3), and “Acceptance Criteria” (Element 6), for the acceptability of the exceptions is as follows:

> Scope of Program - The program is focused on managing the conditions that cause general pitting and MIC of the diesel fuel tank internal surfaces. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

The staff evaluation of the affected GALL Report program elements for acceptability as follows:

> Preventive Action - On a quarterly basis, the diesel generator 7-day fuel oil tanks and the diesel driven fire pump fuel oil tank are tested for water and sediments. Water, if detected, is removed from these tanks. On a monthly basis, or when a diesel generator is running for more than one hour, diesel generator fuel oil day tanks are tested for water and drained as necessary if water is detected. Based on a review of operating experience, these actions are effective in mitigating corrosion inside of diesel generator 7-day fuel oil tanks, diesel generator fuel oil day tanks, and the diesel driven fire pump fuel oil tank.
>
> Parameters Monitored or Inspected - The Fuel Oil Chemistry Program monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 microns, instead of 0.8 microns. These are the principal parameters relevant to tank structural integrity.
>
> Acceptance Criteria - The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. Modified ASTM D 2276, Method A is used for determination of particulates. The modification consists of using a filter with a pore size of 3.0 microns, instead of 0.8 microns.

The applicant concluded that the ASTM D 1796 test method is an acceptable laboratory test method per ASTM D 975-89, “Standard Specification for Diesel Fuel Oils,” for the determination of water and sediment contamination in the Grade 2 fuel oil used at BFN.

> Based on discussions with the applicant and review of implementing procedures, the staff determined that, for fuel oils with the viscosity used at BFN, only ASTM standard D 1796 is applicable. Therefore, the staff found this exception to be acceptable.

Exception 2. In its submittal dated September 14, 2005, the applicant identified an additional exception to GALL AMP XI.M.30 that neither biocides, stabilizers, nor corrosion inhibitors are added to diesel fuel oil at BFN. Water, when detected, is removed from the diesel generator 7-day fuel oil tanks, diesel generator fuel oil day tanks, and the diesel driven fire pump fuel oil tank.

Staff Evaluation: Staff accepts this exception based on a review of plant specific and industry operating experience, removal of water when detected has been effective in mitigating corrosion inside of these tanks. Accordingly, the program description contained in LRA Section A.1.24 was also revised to incorporate this exception.

LRA Section B.2.1.27 did not identify any enhancements; however, the staff noted that an enhancement to achieve consistency with GALL AMP XI.M30, Element 4, “Detection of Aging Effects,” is identified in the applicant’s AMP evaluation basis document. Specifically, the existing Fuel Oil Testing and Monitoring Program needs to be enhanced to include ultrasonic thickness measurements of the tank bottom surfaces to ensure that significant degradation is not occurring.

The program description in LRA Section B.2.1.27 also identifies that a one-time inspection, in accordance with the One-Time Inspection Program, will be performed prior to entering the period of extended operation and will consist of thickness measurements of the 7-day diesel oil supply tanks’ bottom surface. The staff reviewed the One-Time Inspection Program and noted that it provides a general description of items to be included within the scope of the program, but does not specifically identify the 7-day diesel oil supply tank as an item to be inspected.

The staff identified this issue in RAI 7.1.19-1, as documented in the staff’s BFN audit and review report.

In response to this audit RAI and staff follow up on the subject, the applicant stated in a docketed submittal dated May 25, 2005, as follows:

> The One-Time Inspection Program (B.2.1.29) has been revised to specifically identify ultrasonic thickness measurements of the fuel oil storage tank bottom surfaces to ensure that significant degradation is not occurring. To implement this change, the “Program Description” section of LRA Appendix B.2.1.29, One-Time Inspection Program, has been revised to include the following item: “ Ultrasonic thickness measurements of tank bottoms to ensure that significant degradation is not occurring for those tanks specified in the Fuel Oil Chemistry Program (B.2.1.27) and the Aboveground Carbon Steel Tanks Program (B.2.1.26).”

This program description change has been entered into a commitment item and will be suitably incorporated into the Commitment Table in SER Appendix A. The staff considers the response to be acceptable.

Operating Experience. The Fuel Oil Chemistry Program includes identification of water and particulate contamination in the diesel fuel oil system. Corrective actions were taken for the water and particulate contamination removal and system/component inspections. However, there have been no instances of fuel oil system component failures at BFN attributed to contamination.

UFSAR Supplement. In LRA Section A.1.24, the applicant provided the UFSAR supplement for the Fuel Oil Chemistry Program. The staff rev5iewed this section and determined that the information in the UFSAR supplement, with revision, provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined, those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. In its review, the staff identified an enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that, with revision, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Reactor Vessel Surveillance Program

Summary of Technical Information in the Application. The applicant's Reactor Vessel Surveillance Program is described in LRA Section B.2.1.28, "Reactor Vessel Surveillance Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancements, with GALL AMP XI.M31, "Reactor Vessel Surveillance."

The program was implemented to conform to the requirements of 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." The Reactor Vessel Surveillance Program is an integrated surveillance program in accordance with 10 CFR Part 50, Appendix H paragraph III.C, that is based on requirements established by the BWRVIP. Referencing of BWRVIP activities for license renewal was approved by the staff in its SER regarding BWRVIP-74 of October 18, 2001.

The applicant stated that the Reactor Vessel Surveillance Program is described in UFSAR Section 4.2.6 and is based on BWRVIP-78, "BWR Integrated Surveillance Program (ISP) Plan," and BWRVIP-86, "BWR Vessel And Internals Project, BWR Integrated Surveillance Program Implementation." Use of the BWRVIP-78 and BWRVIP-86 was approved for referencing in the staff's safety evaluation dated February 1, 2000. Use of the BWRVIP ISP at Units 2 and 3 was approved by the staff in its safety evaluation dated January 28, 2003.

Enhancement 1. The applicant will confirm that the BWRVIP ISP for the period of extended operation, if approved by the staff for the BWR fleet, is applicable to each reactor vessel and will request the approval from the NRC, if necessary, to use the program at applicable reactor vessels for the period of extended operation. This enhancement is scheduled for completion prior to the period of extended operation, and it affects the program element affected “Scope of Program” (Element 1).

In the LRA, the applicant state that the BWRVIP ISP described in BWRVIP-78 and BWRVIP-86 is only applicable for current license term of 40 years. However, the BWRVIP-78 and BWRVIP-86 ISP provides for 13 capsules to be available for testing during the license renewal period for the BWR fleet and establishes acceptable technical criteria for capsule withdrawal and testing. The BWRVIP has submitted a report, BWRVIP-116, which provides the basis and plan for extending the BWR ISP to address potential extended periods of operation for each unit in the existing U.S. BWR fleet. The staff’s review of BWRVIP-116 is not complete. When the staff review of BWRVIP-116 is complete, the applicant stated that it will evaluate the SER and complete any SER Action Items.

The applicant committed to implement the requirements of BWRVIP-116, when approved, for all three reactor vessels. Therefore, the applicant did not submit a plant-specific program in its LRA.

Enhancement 2. The applicant indicated in the LRA that for Unit 1 it would submit for staff approval the BWRVIP ISP, or a plant-specific surveillance program, that meets the requirements of 10 CFR Part 50, Appendix H for the period of extended operation. The applicant proposed to implement the following actions:

- Capsules will be removed periodically to determine the rate of embrittlement and at least one capsule with neutron fluence of not less than once or greater than twice the peak beltline neutron fluence will be removed before the expiration of the license renewal period.
- Capsules will contain material to monitor the impact of irradiation on the limiting beltline materials and will contain dosimetry to monitor neutron fluence.
- If capsules are not being removed during the license renewal period, operating restrictions (i.e., inlet temperature, neutron spectrum, and flux) will be implemented with NRC approval to ensure that the reactor vessel is operating within the environment of the surveillance capsules, and ex-vessel dosimetry will be supplied for monitoring neutron fluence. This enhancement is scheduled for completion prior to the period of extended operation.

The applicant indicated that a plant-specific withdrawal schedule of the surveillance capsules will be submitted to NRC for final approval in accordance with 10 CFR Part 50, Appendix H prior to entering the period of extended operation.

The applicant concluded that with the implementation of these enhancements, the Reactor Vessel Surveillance Program will be consistent with GALL with respect to the scope of program element for all three units, and this program provides reasonable assurance that the aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions, consistent with the CLB basis, for the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancements and their justifications to determine whether the AMP, with enhancements, remains adequate to manage the aging effects for which it is credited.

In LRA Section B.2.1.28, the applicant described the Reactor Vessel Surveillance Program to manage irradiation embrittlement of the RV through testing that monitors RV beltline materials. The LRA states that the Reactor Vessel Surveillance Program will be enhanced by making it consistent with the BWRVIP ISP for periods of extended operation prior to the BFN units entering their period of extended operation. The LRA further states that the enhanced program will be consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," described in the GALL Report. For this AMP, the GALL Report recommends further evaluation. The staff also reviewed the UFSAR supplement to determine whether it provides an adequate description of the program.

The applicant has implemented the BWRVIP ISP (as documented in BWRVIP-86-A) consistent with the GALL AMP XI.M31, "Reactor Vessel Surveillance," described in the GALL Report for the period of the current units' licenses. The staff concluded that the BWRVIP ISP in BWRVIP-86-A is acceptable for BWR applicant implementation provided that all participating applicants use one or more compatible neutron fluence methodologies acceptable to the staff for determining surveillance capsule and RPV neutron fluences. Staff acceptance of the BWRVIP ISP for the current term is documented in the SER dated February 1, 2002, from Bill Bateman (NRC) to Carl Terry (BWRVIP Chairman). BWRVIP-116 provides guidelines for an ISP to monitor neutron irradiation embrittlement of the reactor vessel beltline materials for all U.S. BWR power plants for the period of license renewal.

The staff's review of LRA Section B.2.1.28 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.1.28-1(A), dated December 1, 2004, the staff requested the applicant to make a commitment to implement BWRVIP-116 ISP, which is currently being reviewed by the staff, or to submit a plant-specific surveillance program for each unit, two years prior to entering the period of extended operation.

In its response, by letter dated January 31, 2005, the applicant indicated that it will implement either BWRVIP-116, as approved by the staff or, if the ISP is not approved two years prior to entering the BFN units' period of extended operation, submit to the staff a plant-specific surveillance program for each unit. The applicant also stated that it will revise LRA Section A.1.25 as shown in the subsection "UFSAR Supplement" of this section. This program description change has been entered into a commitment item and will be suitably incorporated into the Commitment Table in SER Appendix A.

The staff reviewed the applicant’s response and determined that the applicant must make a formal commitment indicating that it will incorporate BWRVIP-116 as approved by the staff or a plant-specific RV surveillance program for each unit, that will satisfy the requirements of 10 CFR Part 50, Appendix H.

In RAI B.2.1.28-1(B), dated December 1, 2004, the staff requested that the applicant provide an explanation for not including Unit 1 in the ISP. The staff also requested that the applicant provide a plant-specific surveillance program for Unit 1, or discuss how Unit 1 will be incorporated into BWRVIP-116, and provide an evaluation of the vessel-to-capsule material compatibility for the limiting plate and weld, as was performed for the ISP program, similar to the other plants specified in BWRVIP-86 and BWRVIP-116.

In its response, by letter dated January 31, 2005, the applicant indicated that LRA Section B.2.1.28 discusses Unit 1 enhancements required to the Reactor Vessel Surveillance Program. The applicant stated in LRA Section B.2.1.28 that, "Unit 1 will be included within the BWRVIP Integrated Surveillance Program, or a plant-specific surveillance program will be submitted for NRC approval that meets the requirements of 10 CFR Part 50, Appendix H for the period of extended operation.”

The applicant indicated that the BWRVIP evaluated the Unit 1 Vessel and Surveillance Program for participation in the ISP. The BWRVIP proposed in its letter from William A. Eaton (Chairman, BWRVIP) to the NRC Document Control Desk, “Project No. 704 – BWRVIP Response to NRC RAIs on BWRVIP-116,” dated January 11, 2005, to include Unit 1 in the ISP. The BWRVIP indicated that Unit 1 is similar in design to the other BWRs in the ISP, and there are no differences in irradiation conditions from the BWR fleet. The BWRVIP evaluated the Unit 1 Reactor Vessel and Surveillance Program for participation in the ISP, consistent with the methods and criteria previously established in BWRVIP-78 and BWRVIP-86 reports. The test capsules representing limiting weld and plate materials are exposed to fluence values that bound Unit 1 extended end of life (EOL) period fluences at the vessel 1/4*t* location. Based on the information provided in the submittal, the staff concluded that the proposed representative materials that are available for use in the ISP for Unit 1 could adequately provide information related to any changes in the fracture toughness properties due to irradiation for the limiting beltline materials during the period of extended operation.

In RAI B.2.1.28-1(C), dated December 1, 2004, the staff requested that the applicant provide its plan associated with testing of the capsules in accordance with the requirements of BWRVIP-116 ISP. The plan should also identify capsules that need not be tested (standby capsules). Tables 2-3 and 2-4 of BWRVIP-116 indicate that capsules from Unit 2 will be tested and capsules from Unit 3 (standby capsules) will be not tested. These untested capsules were originally part of the applicant’s plant-specific surveillance program and have received significant amounts of neutron radiation. The staff requested the applicant to provide its intentions with regard to maintenance of the standby capsules for further use.

In its response, by letter January 31, 2005, the applicant stated:

> Presently, there are no plans to withdraw surveillance capsules from the Unit 3 reactor vessel since the BFN Unit 2 reactor vessel capsule provides the best representative material for both units. As stated in NRC Safety Evaluation of the BWRVIP Integrated Surveillance Program, dated February 1, 2002: “Although some surveillance capsules

> will be deferred and not tested as part of the ISP, all capsules that were previously credited as part of plant-specific surveillance programs will continue to be irradiated in their host reactors. Therefore, all irradiated material samples continue to remain available to the ISP, if needed, and no overall reduction in the number of materials being irradiated, number of specimen types, or number of specimens per reactor occurs as a result of the ISP." Unit 3 surveillance capsules will remain in place and will continue to be irradiated during plant operation, including the period of extended operation. Therefore, the Unit 3 irradiated material samples continue to remain available to the ISP, if needed.

In response the staff requested the following standard license condition required of all LRA applicants to be included in the SER (see SER Section 1.7):

> Any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule which affects the time of withdrawal of any surveillance capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in manner which maintains them in a condition which would support reinsertion into the RV, if necessary.

On the basis of its review, the staff found the applicant had demonstrated that the effects of aging due to loss of fracture toughness of the RV beltline region will be adequately managed with the exceptions as stated above, 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>Operating Experience</u>. The applicant successfully implemented its Reactor Vessel Surveillance Program that is consistent with RG 1.99, Revision 2, 10 CFR Part 50, Appendix H, and ASTM E 185, "Conducting Surveillance Tests For Light Water Cooled Reactor Vessels, E-706," predictions.

<u>UFSAR Supplement</u>. In LRA Section A.1.25, the applicant provided the UFSAR supplement for the Reactor Vessel Surveillance Program.

As noted above, in its response to RAI B.2.1.28-1(A), by letter dated January 31, 2005, the applicant stated that it will revise LRA Section A.1.25 as follows:

> The BFN Reactor Vessel Surveillance Program is mandated by 10 CFR Part 50 Appendix H. The BFN Reactor Vessel Surveillance Program is an integrated surveillance program in accordance with 10 CFR Part 50 Appendix H Paragraph III.C that is based on requirements established by the BWR Vessel and Internals Project. This program will be enhanced to implement either BWRVIP-116, as approved by the staff, or, if the ISP is not approved two years prior to the commencement of the license renewal period, a plant-specific surveillance program for each BFN unit will be submitted that ensures the BFN Unit 1, Unit 2, and Unit 3 reactor vessels meet the requirements of 10 CFR Part 50 Appendix H.

The applicant described the Reactor Vessel Surveillance Program as an existing program in LRA Section A.1.25. The program uses periodic testing of metallurgical surveillance samples to monitor the loss of fracture toughness of the RPV beltline region materials consistent with the requirements of 10 CFR Part 50, Appendix H and ASTM E 185. In its response regarding the standby capsules (stated above), the applicant indicated that it would use Unit 3 surveillance capsules as standby capsules for the period of extended operation.

In a follow up on March 29, 2005, to RAI B.2.1.28-1(A), the staff requested the applicant to commit that any changes to the BWRVIP ISP capsule withdrawal schedule must be submitted for staff review and approval. Any changes to the BWRVIP ISP capsule withdrawal schedule that affects the time of withdrawal of any surveillance capsules must be incorporated into the licensing basis. If any surveillance capsules are removed without the intent to test them, these capsules must be stored in a manner that maintains them in a condition that would support re-insertion into the RV, if necessary. Units 1 and 3 surveillance capsules (standby capsules) will remain in place and will continue to be irradiated during plant operation, including the period of extended operation. Therefore, Units 1 and 3 irradiated material samples continue to remain available to the ISP, if needed.

In its response dated May 25, 2005, the applicant agreed to comply with the staff request. This satisfactorily resolves the staff RAI B.2.1.28-1(A). This program description change has been entered into a commitment item and will be suitably incorporated into the Commitment Table in SER Appendix A.

The staff reviewed the applicant's proposed revision to LRA Section A.1.25 and determined that the applicant must implement the most recent staff-approved version of the BWRVIP ISP as the method to demonstrate compliance with the requirements of 10 CFR Part 50, Appendix H.

The staff concluded that the information provided in the UFSAR supplement for the aging management of systems and components discussed above is equivalent to the information in the SRP-LR and, therefore, provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI responses, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff found that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 ASME Section XI Subsection IWE Program

Summary of Technical Information in the Application. The applicant's ASME Code Section XI Subsection IWE Program is described in LRA Section B.2.1.32, "ASME Section XI Subsection IWE Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with exceptions, with GALL AMP XI.S1, "ASME Section XI Subsection IWE."

The ASME Section XI Subsection IWE Inservice Inspection Program includes visual examination and augmented inspection (visual and/or volumetric examinations) for steel containments (Class MC). Inspections or testing are conducted on the steel containment shells and their integral attachments; containment hatches and airlocks; seals, gaskets, and moisture barriers; and pressure-retaining bolting. As required by 10 CFR 50.55a paragraph (g)(4)(ii), the ASME Code Section XI Subsection IWE Inservice Inspection Program will incorporate the requirements of the latest edition and addenda of the ASME Code by reference into 10 CFR 50.55a paragraph (b) 12 months prior to the start of each 120-month inspection interval, subject to the limitations and modifications listed in 10 CFR 50.55a paragraph (b) and with alternatives as authorized by the staff in accordance with 10 CFR 50.55a paragraphs (a)(3) and (g)(6). Inspection of Class MC components, covered in the subsection IWE, is performed in accordance with the 1992 edition through 1992 addenda for BFN current inspection intervals.

Based on the description of the program, the applicant, in its evaluation of the AMP, concluded that the continued implementation of the ASME Code Section XI Subsection IWE Inservice Inspection Program provides reasonable assurance that the aging effects will be managed so that the structures within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

Staff Evaluation. During its review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the exceptions and their justifications to determine whether the AMP, with exceptions, remains adequate to manage the aging effects for which it is credited.

The staff evaluation consists of identifying and accepting departures from the provisions of the GALL Report. In the program description, the applicant takes three exceptions, which are discussed as follows.

Exception 1. The ASME Code Section XI, 1992 Edition, 1992 Addenda requires visual examination VT-3 of containment seals and gaskets. In lieu of a visual examination, BFN takes an exception to this requirement and requests exception that the test be performed in accordance with the 10 CFR 50 Appendix J Program to determine degradation of seals and gaskets. The applicant, in evaluating this exception, stated that examination of most seals and gaskets require the joints to be disassembled. When the airlocks, hatches, electrical penetrations, and flanged connections are tested in accordance with 10 CFR 50 Appendix J, degradation of the seal or gasket material is revealed by an increase in the leakage rate. Corrective measures can then be applied and the component re-tested. The applicant received a relief from these requirements for Units 2 and 3 for the current interval.

Exception 2. The applicant seeks a second exception to the ASME Code of record for BFN, which requires torque or tension testing on pressure-retaining bolted connections that have not been disassembled and reassembled during the inspection interval. The applicant, however, seeks to perform a test conforming to 10 CFR 50 Appendix J testing in lieu of a bolt torque or tension test as required by the Code for these bolted connections. There is current relief that authorizes this for Units 2 and 3 for the current interval.

<u>Exception 3</u>. The applicant seeks a third exception to the ASME Code, which requires that, when component examination results require evaluation of flaws, areas of degradation, or repairs in accordance with article IWE-3000, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period listed in the schedule of the inspections program. When the reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, the areas containing such flaws, degradation, or repairs no longer require augmented examination in accordance with Table IWE-2500-1 Examination Category E-C. At BFN, if the repair has restored the component to an acceptable condition, reexaminations during subsequent inspection periods are not performed.

(1) Scope of Program - In the LRA, the scope of the program is as described in IWE-1000 of Subsection IWE, of the ASME Code together with the exemptions as identified in IWE-1220, and additional requirements for inaccessible areas as promulgated in 10 CFR 50.55a(b)(2)(ix). The staff found that the plant-specific program scope is in conformance with Section XI.S1 of the GALL Report. Therefore, the staff found the program element acceptable.

(2) Preventive Action - The applicant does not take exception to the program element.

(3) Parameters Monitored or Inspected - The staff evaluated this program element and studied the impacts on Exceptions 1 and 2.

    Staff evaluation: Exception 1 - ASME Code Examination Category E-D of Table IWE-2500-1 requires visual examination of pressure boundary seals and gaskets. The applicant stated in Exception 1 that it utilizes tests performed in accordance with 10 CFR 50 Appendix J, in lieu of a visual examination, to determine degradation of seals and gaskets. In order to evaluate the exception, the staff needed additional information.

    In RAI 3.5-2, dated December 10, 2004, the staff inquired about the aging management of containment penetration seals and gaskets by pointing out that seals and gaskets related to containment penetrations (in Item Number 3.5.1-6 of Table 3.5.1) are proposed to be managed by the Containment Inservice Inspection Program and the Containment Leak Rate Testing Program. As a result of Exception 1 to the ASME Code Section XI Subsection IWE Program, the staff questioned whether the AMP will be applicable for aging management of containment seals and gaskets. The staff said that for equipment hatches and air-locks at BFN, the approach is that the leak rate testing program will monitor aging degradation of seals and gaskets, as they are leak rate tested after every opening. The staff wanted the applicant to clarify whether the assumptions are correct. The staff also requested information for mechanical and electrical penetrations with seals and gaskets, if the Type B leak rate testing and frequency was adequate to monitor aging degradation of seals and gaskets of containment drywell. The staff also requested the status of inspection and conditions of the seals and gaskets of these penetrations at Unit 1.

    With regard to Unit 1, the applicant stated that a Type B test will be performed as part of the Unit 1 restart effort, and will continue to test at a frequency of 30 months until sufficient test performance data are available to justify an extended test interval under Option B.

Details of RAI 3.5-2 are provided in SER Section 3.5.2.3.1. The staff, in evaluating the applicant response, concluded that the applicant satisfactorily described the existing process used in identifying degradation of the primary containment penetration seals and gaskets. Also, since the applicant plans to continue with the testing and corrective action process during the period of extended operation, the staff found the applicant's process of managing the aging of the pressure-retaining seals and gaskets of primary containments and the exception under this program element acceptable.

Staff evaluation of Exception 2 - ASME Code requires torque testing of pressure-retaining bolts of Examination Category E-G, item E8.2 of Table IWE-2500-1. The applicant in exception 2, takes exception from the ASME requirement and requests to perform a test conforming to 10 CFR Part 50, Appendix J testing in lieu of a bolt torque or tension test. The staff has provided relief to this IWE requirement to a number of PWR licensees; however, in the case of BWR containments, the staff has a concern about the adequacy of Type A, Appendix J, leak rate testing to monitor the aging degradation of drywell head bolts, particularly as the Type A testing interval has been extended to 10 and 15 years. During the AMR results review, staff developed RAI 3.5-3 for the applicant's response.

In RAI 3.5-3, dated December 10, 2004, the staff requested information about the testing and inspection of drywell-head components by noting that the containment drywell-head to drywell joint consists of a pressure unseating containment boundary with pre-loaded bolts. Loosened bolts and deteriorated gasket and/or seal can breach containment pressure boundary. The staff felt that Exceptions 1 and 2, taken in the containment ISI program will preclude examinations of seals and bolts of this joint. The staff contended that only Type A leak rate testing and associated visual examination requirements of Appendix J Program can be relied upon to detect defects and degradation of this joint, whose test interval can be 10 to 15 years. The applicant was requested to provide information regarding the plans and programs that are used to ensure the integrity of this joint for each containment. The staff also requested the applicant to provide the status of the components (O-rings and bolts) at this joint for Unit 1.

In its response to RAI 3.5-3, dated January 31, 2005, the applicant stated that these containment pressure boundary components will continue to be inspected consistent with the BFN CLB under 10 CFR Part 50, Appendix J Program requirements. On Units 2 and 3 the Type A test frequency is currently on a 10-year interval. There have been no performance-based Type A test failures on Units 2 or 3. The applicant in its response stated that a Type A Integrated Leak Rate Test will be performed on Unit 1 prior-to-restart. Type B testing is also performed on the drywell-head seal every refueling outage for all three units. Therefore, with the combination of the Type A tests and Type B tests, integrity for this joint for each containment is assured. Exception 2 pertains to bolt torque or tension testing. Pressure-retaining bolting associated with the containment drywell-head to drywell joint is examined in accordance with ASME Code Section XI, Subsection IWE. The staff is satisfied that these two activities together with periodic Type A testing will ensure the integrity of this joint.

Therefore, the staff found the applicant's practice of ensuring the integrity of this joint acceptable and the exception 2 as proposed is acceptable.

(4) Detection of Aging Effects - The applicant does not take exception to the program element.

(5) Monitoring and Trending - The staff evaluated this program element and studied the impacts of exception 3 on it. This exception concerns component examination results that require evaluation of flaws, areas of degradation, or repairs in accordance with Article IWE-3000, of ASME B&PV code (see above). The applicant in performing a plant-specific evaluation of this element stated that the staff previously granted the applicant a relief request (CISI-3) for Units 2 and 3 for its current inspection intervals from the requirement of Paragraphs IWE-2420(b) and IWE-2420(c) to perform reexaminations during subsequent inspection periods of the repaired areas if the repair has restored the component to an acceptable condition. In evaluating the exception, the staff took the position that if flaws and degradations had been repaired and restored in accordance with the requirements of IWA-4000, the staff provided relief to a number of licensees (and applicants) from the requirements of IWE-2420(b) and (c). In granting that relief, staff considered the requirements as an unnecessary burden without a commensurate safety benefit. Therefore, the staff found the exception as it impacted this program element acceptable.

(6) Acceptance Criteria - Acceptable, as no exception taken to GALL AMP X1.S1.

(7) Corrective Actions - The applicant does not take exception to the program element.

(8) Confirmation Process - Acceptable, as no exception taken to GALL AMP X1.S1.

(9) Administrative Controls - Acceptable, as no exception taken to GALL AMP X1.S1.

(10) Operating Experience - The applicant reviewed plant-specific ASME Section XI, Inservice Inspection Program performance results that have been generally effective in managing aging effects in ASME components. In LRA Section B.2.1.32, the applicant provided the following description of plant-specific operating experience.

The drywell steel containment vessel is inaccessible (except for the drywell head) for visual examination from the outside surface. There has been evidence of water leaking from the sand bed drains on both Units 2 and 3. Since there is a horizontal weld connecting the first and second course of drywell liner plates approximately 8 inches above the drywell concrete floor, UT thickness measurements from the drywell floor up to this weld around the drywell circumference would conservatively bound the sand pocket area. UT thickness measurements of this area were obtained during the U2C10 and U3C8 refueling outages for Units 2 and 3, respectively, and in 1999 and 2002 for Unit 1. The data indicated that the condition of the drywell steel liner plate in this area is good, and that this area did not require augmented examination.

The internal drywell steel containment vessel embedment zone is subject to corrosion if the drywell floor-to-containment vessel moisture barrier fails, allowing moisture intrusion; or if the concrete floor of the drywell cracks, allowing moisture seepage through to the steel liner. During the Unit 2 U2C9 outage, a portion of the moisture barrier was replaced. Inspection of the exposed drywell steel containment vessel area below the moisture seal indicated some minor pitting and localized rust, but there was not a challenge to nominal wall thickness. No propagation of iron oxide to the concrete surface was noted; its presence would have indicated steel containment vessel corrosion below the concrete. The concrete floor above the embedded steel containment vessel is examined as part of the Structures Monitoring Program (B.2.1.36).

Based on existing inspection documentation and maintenance practices, this area has not exhibited signs of accelerated degradation.

The penetration bellows at BFN have no documented failures as a result of routine testing by the BFN Appendix J program or inspections conducted by the Containment Inservice Inspection Program.

Inspections conducted under the Containment Inservice Inspection Program identified some damaged areas of the moisture seal barrier (gaps, cracks, low areas/spots, or other surface irregularities) in Units 2 and 3 that required repair.

<u>Operating experience related to containment structure components</u>: RAI 3.5-5, dated May 24, 2005, provides the details of the follow-up to RAI 3.5-4. The staff found that the applicant comprehensively addressed all the issues. In closing out RAI 3.5-5, the staff concluded that the applicant's program was adequate and acceptable. The disposition and resolution of RAI 3.5-5 can be found in SER Section 3.5.2.3.1.

<u>Operating experience related to torus shells:</u> NRC IN 88-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," describes and discusses the problems associated with corrosion of torus shells. In RAI B.2.1.32-1, dated December 10, 2004, the staff asked the applicant to provide information regarding the status of torus shells. In applying NRC IN 88-82, the staff requested the applicant to provide operating experience related to inspection of torus shells at BFN. since the quality of torus water in Unit 1 torus may not have been monitored during its long layup period, the staff requested additional discussion of the condition of the torus for Unit 1.

In its response, by letter January 31, 2005, the applicant stated that the torus interior surfaces at the waterline were subject to corrosion due to moisture and repeated wetting and drying in the waterline region. Accessible portions of the torus inside surface were inspected each refueling outage. UT thickness measurements taken in torus underwater areas of both Units 2 and 3 revealed no evidence of excessive degradation (all readings were within 10 percent of nominal wall thickness). The applicant confirmed that previous inspections had documented evidence of minor coating degradation at the waterline region. Based on the above, the applicant concluded that the underwater region of the torus had not been subjected to accelerated degradation.

The applicant, furthermore, stated that, since evidence of repeated loss of coatings had been documented in the waterline region, augmented examination of this area was warranted as a conservative measure on Units 2 and Unit 3.

Regarding Unit 1, the applicant stated that during its layup period, the water in the Unit 1 torus (pressure suppression pool) was maintained by the "chemistry program." The torus was drained in the summer of 2003 for coating repair, which will be completed as a part of the Unit 1 recovery effort. The applicant also stated that a VT-3 visual examination was performed on the Unit 1 torus in August 2003. This examination included 100 percent of the Code Class MC boundary inside the torus, which included shell and ring girders, and both sides of the vent system to include main vent line, vent header, and downcomers. The visual examination found light-to-medium rust or discoloration in several areas and heavy rust in smaller, less frequent areas. There were also some instances of base metal encroachment, such as gouges, scratches, and tool marks. Engineering evaluation of the examination results determined that the torus structural condition was acceptable as is, with no base metal repairs required.

Moreover, the applicant emphasized that the requirements of ASME Section XI Inservice Inspection Subsection IWE, 1992 Edition with the 1992 Addenda will be implemented on Unit 1. Type A, B, and C leak rate testing required by 10 CFR 50, Appendix J will also be performed prior to Unit 1 restart.

The applicant reviewed site-specific work history data to confirm that an adequate number of inspection opportunities are afforded by the IWE program. The applicant also stated in the LRA that the plant Corrective Action Program, which captures internal and external plant operating experience issues, provides reasonable assurance that operating experience will be reviewed in the future to provide objective evidence to support the conclusion that the effects of aging will be managed adequately.

The staff found the applicant's process of monitoring the condition of the torus in Units 2 and 3 acceptable, as its continuation during the period of extended operation provides adequate assurance regarding the ability of the torus to perform its intended function. The applicant stated in its response letter dated January 31, 2005, that it monitored the quality of water and condition of torus surfaces in the immediate past (since 2003), and plans to continue the ISI activities in accordance with this AMP. Therefore, the staff found the applicant's procedures acceptable, as they will ensure the ability of the torus to perform its pressure-retaining function during the period of extended operation.

<u>UFSAR Supplement</u>. In LRA Section A.1.29, the applicant provided the UFSAR supplement for the ASME Code Section XI Subsection IWE Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review, RAI responses, and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 ASME Section XI Subsection IWF Program

<u>Summary of Technical Information in the Application</u>. The applicant’s ASME Code Section XI Subsection IWF Program is described in LRA Section B.2.1.33, “ASME Section XI Subsection IWF Program.” In the LRA, the applicant stated that this is an existing program. This program is consistent with GALL AMP XI.S3, “ASME Section XI Subsection IWF.”

The LRA states that 10 CFR 50.55a imposes the inservice inspection requirements of the ASME B&PV Code Section XI for Class 1, 2, and 3 piping and component supports. Inspection of equivalent Class 1, 2, and 3 piping and component supports covered in subsection IWF is performed in accordance with the 1995 edition through the 1996 addenda for the Units 1 and 2 current inspection interval. Inspection of equivalent Class 1, 2, and 3 piping and component supports covered in subsection IWF is performed in accordance with the 1989 edition and Code Case N-491 "Alternative Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Power Plants, Section XI Division 1," for the Unit 3 current inspection interval.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the exception and its justifications to determine whether the AMP remains adequate to manage the aging effects for which it is credited.

In RAI B.2.1.33-1, dated December 13, 2004, the staff requested the applicant to address how the supports of MC piping and components are inspected during the current licensing term.

In its response, by letter dated January 18, 2005, the applicant stated:

> The Class MC boundaries include the steel containment vessel (SCV), which is comprised of the drywell, pressure suppression chamber or torus and associated vent piping, including vertical and circumferential structural stiffeners; penetrations, reinforcement structure, the portion of the SCV embedded in the drywell concrete floor slab, and attachment welds between structural attachments and the SCV pressure retaining boundary or reinforcing structure.

The applicant stated that there is no Class MC piping at BFN. Piping in the scope of license renewal located in the containment that is not ASME equivalent Class 1, 2, or 3 is evaluated as non-ASME piping, and covered in its AMR. The staff considered the above classification of the MC component supports to be acceptable. Therefore, the staff's concern described in RAI B.2.1.33-1 is resolved with regard to piping.

By letter dated January 24, 2005, the applicant responded that the ASME equivalent supports and component listed in LRA Table 2.4.8.1 do not include the drywell lower ring support and the drywell upper lateral support. The staff was not clear regarding the applicant's basis for excluding the supports for Class MC components from the scope of ASME Section XI. The staff requested that the applicant justify the above noted exclusion. In its response, by letter dated May 31, 2005, the applicant stated that it will manage the Class MC supports per Section XI, Subsection IWF. LRA Table 3.5.2.26 has been revised to reflect this commitment. Therefore, the staffs concern described in RAI B.2.1.33-1 is resolved with regard to support.

In RAI B.2.1.33-3, dated December 13, 2004, the staff requested the applicant to describe the method by which the supports on Class MC components in inaccessible areas will be managed during the period of extended operation because the applicant's discussion of the IWF Program is focused on accessible supports on MC components. There is no discussion of components in inaccessible areas. In its response, by letter dated January 18, 2005, the applicant stated that none of the torus cradles, downcomer supports, or vent header supports located in containment air or inside air environments are inaccessible. For the vent downcomer and vent header supports that are submerged in a torus water environment, the applicant stated that the Chemistry Control Program and One-Time Inspection Program will be used to manage the aging effects. The staff considered the applicant's response to have adequately addressed its concern on the aging management of inaccessible supports of MC components. RAI B.2.1.33-3 is, therefore, closed.

Based on the information provided in the LRA and the applicant's responses to the RAIs, the staff found that the applicant's IWF Program is acceptable and no exceptions were taken. The supports of MC components will be adequately managed during the period of extended operation.

Operating Experience. The applicant did not indicate any adverse operating experience for this program.

UFSAR Supplement. In LRA Section A.1.30, the applicant provided the UFSAR supplement for the IWF Inspection Program The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, the staff found that the applicant's IWF program is consistent with Section XI.S3 of the GALL. Based on the information provided by the applicant, the staff concluded that the accessible supports of the MC components will be adequately inspected by the IWF Program during the period of extended operation. The staff concluded that the effects of aging will be adequately managed 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). The staff also reviewed the UFSAR Supplement program summary for the IWF Program and concluded that, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.22 Masonry Wall Program

Summary of Technical Information in the Application. The applicant's Masonry Wall Program is described in LRA Section B.2.1.35, "Masonry Wall Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with an enhancement, with GALL AMP XI.S5, "Masonry Wall Program."

In LRA Section B.2.1.35, the applicant stated that the Masonry Wall Program provides for condition monitoring of masonry walls. The program is included in the Structures Monitoring Program that implements the structures monitoring requirements of 10 CFR 50.65 Maintenance Rule. Masonry wall condition monitoring is based on guidance provided in NRC Bulletin 80-11 "Masonry Wall Design" and IN 87-67 "Lessons Learned from Regional Inspections of Licensee Actions in Response to I.E. Bulletin 80-11." Visual inspections are performed consistent with techniques identified in industry codes and standards such as American Concrete Institute (ACI) 349.3 R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and ANSI/American Society of Civil Engineers (ASCE) 11-90, "Guideline for Structural Condition Assessment of Existing Buildings."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancement and its justifications to determine whether the AMP, with enhancement, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) for the Masonry Wall Program and its associated bases documents, and compared them to those listed for AMP XI.S5 in the GALL Report for consistency.

Enhancement. In the LRA Section B.2.1.35, the applicant identified an enhancement to make this AMP consistent with GALL AMP XI.S5. Program procedures will be revised so that structures with masonry walls within the scope of license renewal are clearly identified and the qualification requirements for personnel who perform masonry wall walkdowns within the scope of license renewal are clarified. This enhancement is scheduled to be completed prior to entering the period of extended operation. The applicant concluded that, with the implementation of this enhancement, BFN will ensure continued consistency with the affected program elements.

The staff evaluation of the affected GALL Report program elements, "Scope of Program" (Element 1), "Parameters Monitored or Inspected" (Element 3), and "Detection of Aging Effects" (Element 4), for the acceptability of the exception is as follows:

> Scope of Program. The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4
>
> Parameters Monitored or Inspected. The primary parameter monitored is wall cracking that could invalidate the evaluation basis.
>
> Detection of Aging Effects. Visual examination of the masonry walls by qualified inspection personnel is sufficient. The frequency of inspection is selected to ensure there is no loss of intended function between inspections. The inspection frequency may vary from wall to wall, depending on the significance of cracking in the evaluation basis. Unreinforced masonry walls that have not been contained by bracing warrant the most frequent inspection, because the development of cracks may invalidate the existing evaluation basis.

GALL AMP XI.S5 states that the scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The AMP evaluation states that structures with masonry walls within the scope of license renewal include the BFN reactor buildings, Unit 1 and 2 diesel generator building, Unit 3 diesel generator building, Unit 2 turbine building (station blackout (SBO) function), and the intake pumping station. BFN Technical Instruction 0-TI-346 will be enhanced to identify that the Unit 1,2, and 3 reactor buildings, Unit 1 and 2 diesel generator building, Unit 3 diesel generator building, Unit 2 turbine building (SBO function), and the intake pumping station are within the scope of license renewal.

The staff requested that the applicant identify the walls that are within the scope of license renewal. The applicant, as documented in the staff's audit and review report, stated that BFN Technical Instruction 0-TI-346 identifies structures within the scope of license renewal for the Maintenance Rule and will be enhanced to identify structures within the scope of license renewal that require aging management. LCEI-CI-C9 refers to BFN Technical Instruction 0-TI-346 for the detailed listing of structures in the scope of the Maintenance Rule and license renewal. LCEI-CI-C9 requires inspection of masonry walls in structures identified in BFN Technical Instruction 0-TI-346. The staff concurred that, with the enhancement, all the masonry walls that are within the scope of license renewal will be covered by the referenced procedures.

GALL AMP XI.S5 also states that visual examination of the masonry walls by qualified inspection personnel is sufficient. The BFN AMP evaluation states that the quality and value of the results obtained from the walkdown assessment activity and the assessment evaluation are dependant on the qualifications and capabilities of the inspection team, as discussed in Chapter 7 of ACI 349-3R-96. LCEI-CI-C9 will be enhanced as part of the Structures Monitoring Program enhancements to clarify the qualification requirements for personnel who perform masonry wall walkdowns and evaluations. The staff concurred that this enhancement is consistent with the GALL Report. See the SER Section on Structures Monitoring Program below for information on enhancements to the Structures Monitoring Program.

UFSAR Supplement. In LRA Section A.1.32, the applicant provided the UFSAR supplement for the Masonry Wall Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.23 Structures Monitoring Program

Summary of Technical Information in the Application. The applicant's Structures Monitoring Program is described in LRA Section B.2.1.36, "Structures Monitoring Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program."

In the LRA Section B.2.1.36, the applicant stated that the Structures Monitoring Program includes periodic inspection and monitoring of the condition of accessible areas of structures. The Structures Monitoring Program implements the requirements of 10 CFR 50.65, "Maintenance Rule." The program incorporates the guidance of RG 1.160, Revision 2, and Nuclear Management and Resources Council 93-01, Revision 2. The Structures Monitoring Program provides inspection guidelines and walkdown checklists for concrete features, roofs, structural steel, masonry walls, seismic gaps, tanks, earthen structures, buried piping, and miscellaneous components such as doors.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancements and justifications to determine whether the AMP, with enhancements, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP and associated bases documents, and compared them to those listed for AMP XI.S6 in the GALL Report for consistency.

The staff noted that the basis document does not address protective coating monitoring and maintenance; however, BFN Technical Instruction 0-TI-346 Section 3.3 includes "damaged/degraded coatings" under concrete and structural steel. LCEI-CI-C9 does not address protective coatings in the walkdown procedures. As documented in the staff's audit and review report, the applicant confirmed that protective coatings are not credited to manage aging effects for license renewal.

The staff noted that the program is being expanded to include the inspection of piles and asked the applicant to clarify the types of inspections that will be performed for piles. The applicant stated that piles associated with gate structure Number 3 and the diesel high pressure fire protection (HPFP) house will be visually inspected by the Structures Monitoring Program. The portion of the piles exposed to the submerged and outside air environments will be visually inspected by the Structures Monitoring Program. The staff concluded that the AMP would not require any further enhancements to perform the inspections of piles as described by the applicant.

In LRA Section B.2.1.36, the applicant identified three enhancements to make this AMP consistent with GALL AMP XI.S6.

Enhancement 1. The applicant will enhance procedures implementing the 10 CFR 50.65 Maintenance Rule Program to identify all structures and structural components within the scope of license renewal and all aging effects and associated mechanisms for inspection. The staff evaluation of the affected GALL program elements "Scope of Program" (Element 1) and "Parameters Monitored or Inspected" (Element 3), for the acceptability of the first enhancement is as follows:

> Scope of Program. The applicant specifies the structure/aging effect combinations that are managed by its Structures Monitoring Program.
>
> Parameters Monitored or Inspected. For each structure/aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Parameters monitored or inspected are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and American National Standards Institute (ANSI)/ASCE 11-90 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable). If necessary for managing settlement and erosion of porous concrete

subfoundations, the continued functionality of a site dewatering system is to be monitored. The plant-specific Structures Monitoring Program is to contain sufficient detail on parameters monitored or inspected to conclude that this program attribute is satisfied.

The staff asked the applicant how the structural components and supports that are identified as an enhancement to the scope of the AMP are currently being managed and if a baseline inspection of these structural components and supports will be performed prior to the period of extended operation.

The applicant, as documented in the staff's audit and review report, stated that the identified structural component supports that are to be added to the Structures Monitoring Program are currently being managed by the plant work control procedures and the Corrective Action Program. The applicant further stated that all Structures Monitoring Program enhancements required to document structural components and structural support inspections will receive a baseline inspection prior to the period of extended operation. Structures Monitoring Program baseline inspections are currently required by Section 5.1 of LCEI-CI-C9.

The staff noted that the AMP evaluation states that procedures in BFN Technical Instruction 0-TI-346 and LCEI-CI-C9 will be enhanced to identify all aging effects and associated aging mechanisms to be inspected. Aging effects and mechanisms considered will be consistent with the GALL Report and Section 4 of ACI 349.3R-96. BFN operating experience is considered for selecting each structure/aging effect combination. The aging effects for structures monitored and inspected that will be identified in 0-TI-346 and LCEI-CI-C9 enhancements are documented in the staff's BFN audit and review report.

The staff concurred that this enhancement is consistent with the GALL Report.

<u>Enhancement 2</u>. The applicant will enhance LCEI-CI-C9 implementing the 10 CFR 50.65 Maintenance Rule Program sampling approach to include examinations of representative samples of below-grade concrete when excavated for any reason. The staff evaluation of the affected GALL program element "Detection of Aging Effects" (Element 4) for the acceptability of the second enhancement is as follows:

<u>Detection of Aging Effects</u>. For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific Structures Monitoring Program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.

The staff concurred that this enhancement is consistent with the GALL Report.

<u>Enhancement 3</u>. The staff evaluation of the affected GALL program element "Detection of Aging Effects" (Element 4) for the acceptability of the third enhancement is as follows:

Detection of Aging Effects. (See element description above)

The applicant will enhance LCEI-CI-C9 implementing 10 CFR 50.65, the Maintenance Rule Program, to include the guidance provided in ACI 349.3R-96 Chapter 7 to clarify the "suitably knowledgeable or trained" inspector qualifications to "training and proficiency demonstration of inspectors for structural aging effects and long term performance issues." The procedures will also be clarified to identify the "responsible engineer" as the "Structures Monitoring Program engineer" to avoid confusion with industry guidance. LCEI-CI-C9 will also be clarified to identify the "responsible engineer" as the "Structures Monitoring Program engineer" to avoid confusion with industry guidance.

The staff had a follow up question in a May 4, 2005, teleconference regarding evaluation of inspection personnel qualification based on industry guidance ACI 349.3R-96 as stated in the Structures Monitoring Program. The staff stated that this industry guidance alone will not be adequate to qualify the inspectors for the examination of steel supports for the Structures Monitoring Program. The staff requested that the applicant reevaluate the program element from previous staff positions and submit the description for staff review. The applicant responded to the staff's question and committed to manage the aging effects of Class MC supports under ASME Code Section XI Subsection IWF. In its response to a follow up to RAI B.2.1.33-1, the applicant also agreed to include the inspector's qualification in accordance with the requirements of ASME Code Section XI Subsection IWF and not per the BFN Structures Monitoring Program. In its response to a follow up to RAI B.2.1.33-1,by letter dated May 31, 2005, the applicant responded to the staff's question and committed to manage the aging effects of Class MC supports under ASME Code Section XI Subsection IWF. The applicant also agreed to include the inspector's qualification in accordance with the requirements of ASME Code Section XI Subsection IWF and not per the BFN Structures Monitoring Program.

Subject to the applicant's complying by submitting this resolution of this confirmatory item, the staff concurred that this enhancement is consistent with the GALL Report.

Operating Experience. In LRA Section B.2.1.36, the applicant stated that plant-specific performance results of the Structures Monitoring Program had been reviewed. The program has been shown to be effective in managing aging effects of structural features and components. Examples of the plant-specific operating experience issues are documented in the staff's BFN audit and review report and were determined to be insignificant with respect to maintaining structural adequacy. Defects were identified as PERs and dispositioned in accordance with the Maintenance Rule Program by methods such as repair, cause determination, cause mitigation, or monitoring to ensure the continued availability of the function.

In addition to the operating experience discussed in the AMP, the AMP evaluation stated that a baseline inspection for the Structures Monitoring Program was established in 1997 and is documented in calculation CDQ-0303-970086. Defect evaluations performed since the baseline inspection and inspection results from the 2002 Structures Monitoring Program are documented in calculation CDQ-0303-2003-0260. Observed aging effects for structures within the scope of license renewal were evaluated not to significantly challenge the ability of structures to meet design requirements or perform their intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.33, the applicant provided the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.24 Inspection of Water-Controlled Structures Program

Summary of Technical Information in the Application. The applicant's Inspection of Water-Controlled Structures Program is described in LRA Section B.2.1.37, "Inspection of Water-Controlled Structures Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancements, with GALL AMP XI.S7, "RG 1.127, Inspection of Water-Controlled Structures Associated with Nuclear Power Plants."

In LRA Section B.2.1.37, the applicant stated that the Inspection of Water-control Structures Program manages age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures. BFN is not committed to RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," but has a program in place that is consistent with the elements of RG 1.127, as evaluated in the GALL Report. The program is included in the Structures Monitoring Program (B.2.1.36), which implements the structures monitoring requirements of 10 CFR 50.65 "Maintenance Rule." The Inspection of Water-control Structures Program includes in-service inspection and surveillance activities for dams, slopes, canals, and other water-control structures.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancements and its justifications to determine whether the AMP, with enhancements, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP, associated bases documents, and the implementing documents, and compared them to those listed for AMP XI.S7 in the GALL Report for consistency. The staff did not request any clarifications or additional information from the applicant for this AMP.

Enhancement 1. The applicant will enhance program documents to ensure that required structures and structural components within the scope of license renewal are identified. Although the LRA indicates that this enhancement affects GALL Report program element "Parameters Monitored or Inspected" (Element 3), the staff noted that the description of the enhancement in the LRA more appropriately pertains to GALL Report program element, "Scope of Program" (Element 1). Therefore, the staff evaluated this enhancement against the GALL Report element as follows.

> Scope of Program - 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.

The applicant's AMP basis document (AMP evaluation) states that the scope of the Inspection of Water-Controlled Structures Program includes the following list of structures identified in BFN Technical Instruction 0-TI-346, Attachment 38:

- intake pumping station
- gate structure No. 3
- intake channel
- north bank of cool water channel east of gate structure Number 2
- south dike of cool water channel between gate structure Number 2 and 3 (only that portion of the south dike over the RHRSW discharge piping)

Procedures, 0-TI-346 and LCEI-CI-C9, will be enhanced to identify all structures and structural components within the scope of license renewal. Component enhancements will expand the walkdown checklist of structural steel components to include items such as anchors, bolts, fasteners, and other miscellaneous steel and non-ferrous materials. Component enhancements will also require expanding the checklist for seismic gaps to include seals and caulking that are used to prevent flooding. Component enhancements will be based on the list of structural components within the scope of license renewal in the AMR.

BFN Technical Instruction 0-TI-246 augments LCEI-CI-C9 in that it provides the inspection requirements for water holding or transporting earthen structures. The scope of 0-TI-246 is identified in Appendix A and includes the intake channel, north bank of cool water channel east of gate structure Number 2, and the south dike of cool water channel between gate structure Numbers 2 and 3. Appendix A of BFN Technical Instruction 0-TI-246 will be enhanced to indicate that the intake channel, north bank of cool water channel east of gate structure Number 2, and south dike of cool water channel between gate structure Numbers 2 and 3 (only that portion of the south dike over the RHRSW discharge piping) are within the scope of license renewal and require aging management. The staff concurred that this enhancement is consistent with the GALL Report.

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.

The applicant's AMP basis document states that 0-TI-346 and LCE-CI-C9 provide for monitoring of concrete structures, structural steel, non-ferrous components, and earthen structures. BFN Technical Instruction 0-TI-246 augments LCEI-CI-C9 and provides the inspection requirements for water holding or transporting earthen structures such as ponds, channels, and associated dikes. BFN Technical Instruction 0-TI-346 and LCEI-CI-C9 will be enhanced to identify aging effects and associated aging mechanisms to be inspected, consistent with GALL Chapter III for Group 6 structures, Section 4 of ACI 349-3R-96, and the EPRI Structural Tools document. The aging effects identified in the 0-TI-346 and LCEI-CI-C9 enhancements are included as enhancements to the Structures Monitoring Program. The staff concurred that these enhancements are consistent with the GALL Report.

Enhancement 2. The applicant's program will enhance the documents to include special inspections following the occurrence of large floods, earthquakes, tornadoes, and intense rainfall. The staff evaluation of the affected GALL Report program element "Detection of Aging Effects" (Element 4) for the acceptability of the second enhancement is as follows:

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.

The applicant's AMP basis document states that 0-TI-246 Section 7.2 specifies a special inspection of water-holding or water-transporting earthen structures within 30 days following extreme environment or natural phenomena. LCEI-CI-C9 will be enhanced to include a special inspection for the intake pumping station and gate structure No. 3, following the occurrence of large floods, earthquakes, tornadoes, and intense rainfall. The staff concurred that this enhancement is consistent with the GALL Report.

Operating Experience. In LRA Section B.2.1.37, the applicant stated that plant-specific performance results of the inspection of the Water-Control Structures Program, as implemented by the Structures Monitoring Program to meet the requirements of 10 CFR 50.65, were reviewed. The program has been shown to be effective in managing aging effects of structural features and components. The applicant identified two examples of plant-specific operating experience.

- Intake pumping station: very minor concrete surface cracks and platform grating clipped
- Gate structure No. 3: very minor concrete surface cracks and spalling

Neither was considered significant enough to affect the function of a structure.

In addition to the operating experience discussed in the LRA, the AMP evaluation stated that a review of the operating experience for water-control structures within the scope of license renewal did not identify any PERs (SPP-3.1 Corrective Action Program) related to RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.” A baseline inspection for the Structures Monitoring Program was established in 1997 and is documented in Calculation CDQ-0303-970086. Defect evaluations performed since the baseline inspection and inspection results from the 2002 Structures Monitoring Program are documented in calculation CDQ-0303-2003-0260. The Structures Monitoring Program inspections noted the above aging effects and associated defect evaluations for water-control structures within the scope of license renewal. Observed aging effects for water-control structures in the scope of license renewal were evaluated not to significantly challenge the ability of water-control structures to meet design requirements or perform their intended function.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

The staff found that the applicant had adequately considered operating experience, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.34, the applicant provided the UFSAR supplement for the Inspection of Water-Controlled Structures Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.25 Environmental Qualification Program

Summary of Technical Information in the Application. The applicant's EQ Program is described in LRA Section B.3.1, "Environmental Qualification Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancement, with GALL AMP X.E1, "Environmental Qualification of Electric Components."

LRA Section 4.4 affirms the applicant's compliance with generic safety issue (GSI)-168, "Environmental Qualification of Low-Voltage Instrumentation and Control Cables," and follow-up NRC Regulatory Issue Summary 2003-9, "Environmental Qualification of Low-Voltage Instrumentation and Control Cables," May 2, 2003, which the GALL Report cites as a currently open generic issue with ongoing research.

The applicant follows nuclear station EQ requirements in 10 CFR 50.49. The requirements are that each licensed facility establish an EQ Program to demonstrate that electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments while withstanding the effects of inservice aging. The effects of significant aging mechanisms must be addressed as part of EQ.

In LRA Section B.3.1, the applicant stated that the EQ Program manages component thermal, radiation, and cyclical aging effects through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components are considered TLAAs for license renewal. The staff's evaluation is included in SER Section 4 (see SER Section 4.4).

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancement and its justifications to determine whether the AMP, with enhancement, remains adequate to manage the aging effects for which it is credited.

In LRA Section B.3.1, the applicant stated that the EQ Program is consistent with GALL AMP X.E1. The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP and associated bases documents, and compared them to those listed for GALL AMP X.E1 for consistency. The staff identified three differences in the EQ component reanalysis attributes, as discussed below.

In the AMP basis document, the applicant stated that the analytical models used in the re-analysis of an aging evaluation will, in most cases, be the same as those applied during the initial qualification. However, the description of GALL AMP X.E1 states that the analytical models used in the re-analysis of an aging evaluation should be the same as those previously applied during the prior evaluation. The staff asked under what circumstances the analytical models used in the re-analysis of an aging evaluation would not be the same as those applied during the initial qualification.

The applicant stated, as documented in the staff's BFN audit and review report, that BFN will use the same analytical methods used in the original EQ evaluations. If a different method is used, the basis for using the method will be documented in the EQ package. The staff found this acceptable.

The staff noted that the LRA does not address the recommendation in GALL AMP X.E1 that a representative number of temperature measurements be conservatively evaluated to establish the temperatures used in an aging evaluation.

The applicant, as documented in the staff's audit and review report, stated that BFN currently has no plans to monitor temperatures to extend the qualified life of EQ components. If the need arises, a representative number of temperature measurements will be used to establish the temperature used in the aging analysis. The collection methodology and the data collected will be documented as part of the EQ package. The staff found this acceptable.

The staff also noted that the LRA does not address the recommendation in GALL AMP X.E1 that any changes to material activation energy values as part of a re-analysis are to be justified on a plant-specific basis.

The applicant stated, as documented in the staff's audit and review report, that BFN currently has no plans to change activation energies as part of the evaluation to extend the life of EQ components. If during the evaluation process an activation energy is changed, the basis for changing the value will be documented in the EQ package. The staff found this acceptable.

Enhancement. In LRA Section B.3.1, the applicant identified one enhancement to make this AMP consistent with AMP X.E1 in the GALL Report. The EQ Program will be implemented on Unit 1. The enhancement is scheduled for completion prior to Unit 1 re-start from its current extended outage. The staff found this enhancement acceptable since it will make the applicant's program consistent for all three units.

Operating Experience. In LRA Section B.3.1, the applicant stated that operating experience is a vital consideration in maintaining the current EQ Program and in modifying qualification bases and conclusions, including qualified life. The engineering, technical, and programmatic requirements and processes followed in establishing and maintaining the EQ Program include a review of licensing, industry, and other generic documentation for EQ applications and involvement in various utility groups.

Further, industry operating experience was incorporated into the license renewal process through a review of industry documents to identify aging effects and mechanisms that could challenge the intended function of SSCs within the scope of license renewal. A review of plant-specific operating experience was also performed to identify plant-specific aging effects and none were found.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

The staff found that the applicant had adequately considered operating experience, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.35, the applicant provided the UFSAR supplement for the EQ Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.26 Fatigue Monitoring Program

Summary of Technical Information in the Application. The applicant's Fatigue Monitoring Program is described in LRA Section B.3.2, "Fatigue Monitoring Program." In the LRA, the applicant stated that this is an existing program. This program is consistent, with enhancements, with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

In the LRA, the applicant stated that the Fatigue Monitoring Program is used for management of metal fatigue of select components in the reactor coolant pressure boundary and primary containment. The fatigue monitoring program provides for monitoring fatigue stress cycles to ensure that the design fatigue usage factor limit is not exceeded.

Aging evaluations for fatigue monitored components are considered TLAAs for license renewal. The staff's evaluation is included in SER Section 4 (see SER Section 4.3).

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the BFN audit and review report. Furthermore, the staff reviewed the enhancements and its justifications to determine whether the AMP, with enhancements, remains adequate to manage the aging effects for which it is credited.

The staff reviewed the program elements (see SER Section 3.0.2.1) contained in the AMP basis document and compared them to those listed for AMP X.M1 in the GALL Report for consistency. The staff concluded that the elements of the Fatigue Monitoring Program are consistent with the elements of the AMP in the GALL Report.

The staff during the GALL consistency audit questioned how the current (starting) fatigue cumulative usage factor (CUF) will be calculated for locations to be added to the scope of the Fatigue Monitoring Program, as identified under program enhancements. This is needed as initial input to either a manual or automated tracking system.

The applicant described two alternate fatigue monitoring approaches, (1) stress-based fatigue (SBF) and (2) cycle-based fatigue (CBF), each with a different procedure, used for calculating the starting CUF. The staff reviewed the two procedures and concluded that the procedure to be utilized with CBF, based on plant records of experienced transients, is reasonable and conservative, while the procedure to be utilized with SBF, based on linear projection, is potentially nonconservative. The staff asked the applicant to provide its technical basis for concluding that the procedure to be utilized with SBF is reasonable and conservative, especially in light of the industry operating experience cited by the applicant (i.e., “concerns that early-life operating experience, at some units, had caused CUF values to increase at a faster rate than anticipated in the original plant design”).

The applicant, as documented in the staff’s audit and review report, stated that the same procedure, based on plant records of experienced transients, will be used to calculate the starting CUF for both the SBF and CBF fatigue monitoring approaches. Detailed results of the staff’s onsite audits are documented in “Audit Report for Plant Aging Management Programs and Aging Management Reviews - Browns Ferry Nuclear Plant Units 1, 2, and 3,” dated April 26, 2005. The staff found this acceptable.

Enhancement. In LRA Section B.3.2, the applicant identified an enhancement to make this AMP consistent with AMP X.M1 in the GALL Report. The staff evaluation of the affected GALL program element, “Scope of Program” (Element 1), for the acceptability of the enhancement is as follows:

> Scope of Program. The program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

The applicant will, prior to the period of extended operation, enhance the Fatigue Monitoring Program by using the EPRI-licensed FatiguePro® cycle-counting and fatigue-usage tracking computer program. This program calculates stress cycles and resulting CUF values from operating cycles. These calculations will be automated and performed periodically based on information downloads from the plant’s instrumentation computers. The enhancements will include expansion of the program coverage to include selected reactor vessel locations as specified in LRA Table 4.3.1.1; the locations identified by NUREG/CR-6260 for environmental fatigue evaluation, as discussed in LRA Section 4.3.4 and in accordance with the GALL Report Section X.M1; and fatigue monitoring of the suppression chamber and suppression chamber vents, including the vent headers and downcomers, as specified in LRA Section 4.6.1.

The staff found that the enhanced program will be consistent with GALL AMP X.M1.

Operating Experience. In the LRA, the applicant stated that since the original licensing of BFN, the industry has sponsored the development of the EPRI-licensed FatiguePro® computer program. This action was taken in response to staff concerns that early-life operating experience at some units had caused CUF values to increase at a faster rate than anticipated in the original plant design. This program provides for the incorporation of operating experience, and is designed to ensure that the CUF values do not exceed acceptable limits in the remainder of a unit’s operating life.

The staff found there is reasonable assurance that the Fatigue Monitoring Program will be effective in monitoring fatigue usage factors at critical locations, on the basis that the program is consistent with GALL AMP X.M1.

During the onsite audit, the staff noted that the applicant incorporates internal and external plant operating experience issues into the plant Corrective Action Program on a continuing basis. The staff concluded there is reasonable assurance that operating experience will continue to be reviewed in the future to ensure that the effects of aging will be adequately managed.

UFSAR Supplement. In LRA Section A.1.36, the applicant provided the UFSAR supplement for the Fatigue Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant had 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 concluded 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 Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following plant-specific AMPs:

- Systems Monitoring Program (B.2.1.39)
- Bus Inspection Program (B.2.1.40)
- Diesel Starting Air Program (B.2.1.41)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.2.1.13)

For 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 were adequate to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following sections of this SER.

3.0.3.3.1 Systems Monitoring Program

Summary of Technical Information in the Application. The applicant's Systems Monitoring Program is described in LRA Section B.2.1.39, "Systems Monitoring Program." In the LRA, the applicant stated that this is an existing plant-specific program.

<u>Staff Evaluation</u>. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.1.39, regarding the applicant's demonstration of the Systems Monitoring Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Systems Monitoring Program against the AMP elements found in the SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1, and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - In LRA Section B.2.1.39, the applicant stated that the program requirements are for visual inspections to identify material condition (i.e., loss of material, corrosion etc) of surfaces and components within the scope of license renewal as identified in the AMRs. The staff found the scope of the program to be comprehensive and acceptable because it includes the components that credit this program, as identified in the AMR tables.

    The staff confirmed that the scope of the program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.1.39, the applicant stated that the Systems Monitoring Program is a condition monitoring program; thus, there are no preventive actions. The staff concurred with this assessment and does not identify the need for any preventive actions associated with this program.

    The staff confirmed that the preventive actions program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The LRA states that the Systems Monitoring Program includes visual inspections to identify material condition (i.e., loss of material, corrosion, etc.) of surfaces of systems and components prior to the loss of their intended function. The staff found that the parameters monitored or inspected will provide symptomatic evidence of potential degradation and, therefore, are acceptable.

    The staff confirmed that the parameters monitored or inspected program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.1.39, the applicant stated that the program includes visual inspections to identify material condition (i.e., loss of material, corrosion, etc.) of surfaces of systems and components prior to the loss of their intended function. The system visual inspections are performed on a periodic basis and provide for data collection on systems and components for monitoring and trending to ensure timely detection of aging effects. Visual inspection is a continuous process with results periodically reported in system health reports.

The staff's review of LRA Section B.2.1.39 identified an area in which additional information was necessary to complete the review of the applicant's program element. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.1.39-1, dated October 12, 2004, the staff asked the applicant if a sampling approach is used and, if so, to justify that the sample size is adequate. The applicant was also requested to clarify how external surfaces of systems that are covered by insulation, or are located in normally inaccessible areas, are to be visually inspected. Further, the applicant was requested to clarify how elastomer degradation would be detected by visual inspection and to clarify how external surface inspections would detect internal aging effects caused by exposure to treated water for the flexible connectors in the diesel generator system.

In its response by letter dated November 3, 2004, the applicant clarified that visual inspection is performed on accessible components during system walkdowns and that visual inspections should encompass all or part of the total accessible system, such that the entire system is covered over time. The applicant also clarified that the portions of the system that are inaccessible during power operation should be walked down during the refueling outages or forced outages. In regard to flexible connectors in the diesel generator system, the applicant explained that the AMP identified by the LRA is incorrect and that the internal aging effects are managed by the One-Time Inspection Program and the external effects are managed by the Systems Monitoring Program.

The staff found the applicant's response acceptable on the basis that there is reasonable assurance that visual inspections of accessible surfaces of systems and components, combined with inspections during outages, are capable of detecting the aging effects that are covered by this program. The use of visual inspections to detect external degradation is consistent with industry practice.

The staff confirmed that the detection of aging effects program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.1.39, the applicant stated that the inspected systems and components are monitored, trended, and documented by the use of System Health Reports, the Corrective Action Program, and the Corrective Maintenance Program. The staff found that the overall monitoring and trending proposed by the applicant are acceptable because there is reasonable assurance that an effective walkdown program combined with the Corrective Action Program and the Corrective Maintenance Program will effectively manage the applicable aging effects.

The staff confirmed that the monitoring and trending program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.1.39, the applicant stated that during a system or component visual inspection, system engineers use their knowledge of the UFSAR, TSs, design basis documents, operating experience, and the plant operating, technical, and maintenance procedures to evaluate system physical attributes and operational characteristics. In RAI B.2.1.39-1, the applicant was also requested to clarify the acceptance criteria applied in the inspection or evaluation of degradation. In its response, the applicant provided guidance to the system engineer, which is that there should be no evidence of steam or water leakage and system wastage, and that surface condition of welds appear satisfactory. The staff found that a detailed look at the material condition and degraded components by a knowledgeable system engineer, combined with effective corrective actions, are a reasonable approach to detect and evaluate degradation in applying design basis acceptance criteria.

The staff confirmed that the acceptance criteria program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - In LRA Section B.2.1.39, the applicant stated that the Systems Monitoring Program produces system health reports, which provide a review of systems and components' operating experience. The LRA also states that the effectiveness of the corrective actions have been evaluated and documented in system health reports. In RAI B.2.1.39-1, the staff further asked the applicant to identify specific operating experience that provides objective evidence to support the conclusion that the Systems Monitoring Program is effective in managing aging effects on the external surfaces of systems and components within the scope of the program. In the response dated, November 3, 2004, the applicant clarified that the Systems Monitoring Program, through the use of PERs and WOs, tracks and trends corrective actions and provides objective evidence to support a determination that the effects of aging will be adequately managed so that the systems and components intended function will be maintained during the period of extended operation. The staff found that there is reasonable assurance that the applicant's use of system health reports combined with PERs and WOs should provide objective evidence to support the conclusion that the program will adequately manage the aging effects in the systems and components that credit this program. Therefore, the staff's concerns described in RAI.2.1.39-1 are resolved.

The staff confirmed that the operating experience program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

<u>UFSAR Supplement</u>. In LRA Section A.2.1, the applicant provided the UFSAR supplement for the Systems Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI response, and audit of the applicant's program, the staff concluded that the applicant had 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 supplements for this AMP and found that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Bus Inspection Program

Summary of Technical Information in the Application. The applicant's Bus Inspection Program is described in LRA Section B.2.1.40, "Bus Inspection Program." In the LRA, the applicant stated that this is a new plant-specific program.

In the LRA, the applicant stated that the Bus Inspection Program will be initiated prior to the period of extended operation. This commitment is identified on the applicant's license renewal commitment list as Item 38. The applicant stated that this is a non-GALL program and will provide reasonable assurance that the bus ducts will continue to perform their intended function consistent with the CLB through the period of extended operation.

The Bus Inspection Program will provide reasonable assurance that the intended functions of isolated and nonsegregated phase bus will be maintained consistent with the CLB through the period of extended operation. It will manage nonsegregated phase bus insulation exposed to adverse localized environments caused by heat in the presence of oxygen and loosening the fastening hardware associated with isolated and non-segregated phase bus due to cyclic loading resulting in thermal expansion and contraction. The program will also include inspection of the bus enclosure.

This program will manage all portions of isolated and non-segregated phase bus associated with the unit station service transformers, main transformers, and common station service transformers within the scope of license renewal.

The aging mechanisms managed by this program include degradation of the nonsegregated phase bus insulation caused by heat in the presence of oxygen and cyclic loading of isolated and non-segregated phase bus causing thermal expansion and contraction of the bus, which could loosen the bus connection fastening hardware. Any one of these conditions could lead to a failure, preventing the phase bus from performing its intended function.

The program will be performed in conjunction with routine maintenance activities. The program will include visual inspection and electrical testing of in-scope, non-segregated phase bus for evidence of loosened bolted bus connections and damage to bus insulation. The program will also include visual inspection and electrical testing of in-scope isolated phase bus for evidence of loosened bolted bus connections and visual inspection of the in-scope isolated and non-segregated phase bus enclosure for excessive dust build up, evidence of water intrusion, and debris.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.1.40, regarding the applicant's demonstration of the Bus Inspection Program to ensure that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Bus Inspection Program against the AMP elements found in SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1, and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

The staff's review of LRA Section B.2.1.40 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI, as discussed below.

In RAI 3.6-4, dated November 4, 2004, the staff requested the applicant to provide additional information regarding details of the program elements of the AMP.

In its response, by letter December 9, 2004, the applicant provided the augmented details for the seven program elements as follows.

(1) Scope of Program - This program applies to the isolated phase bus duct, as well as the non-segregated bus ducts associated with the unit station service transformers, main transformers, and common station service transformers within the scope of license renewal.

    The staff confirmed that the scope of the program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.1.40, the applicant stated that the Bus Inspection Program will be a condition monitoring program. No actions will be taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff found no need for such actions.

    The staff confirmed that the preventive actions program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - In LRA Section B.2.1.40, the applicant stated that the bus insulation will be visually inspected for embrittlement, cracking, melting, discoloration, or other damage. In addition, the bus insulation will be tested using a proven test for detecting deterioration of the insulation system, such as insulation resistance, or other testing that is state-of-the-art at the time the test is performed. The specific type of test performed will be determined prior to the initial test. Bolted bus

connections will be visually inspected for evidence of burning or heat-up on tape connections, loose connections or arcing on boot-type cover sleeves, and evidence of tracking, corrosion, or ground faults on uninsulated connections. In addition, the bolted bus connections will be tested using a proven test for detecting deterioration of the bolted connection, such as micro-ohm resistance or other testing that is state-of-the-art at the time the test is performed. The specific type of test performed will be determined prior to the initial test.

The applicant stated that the bus enclosure internal will be visually inspected for foreign debris, excessive dust build-up, and evidence of water intrusion. Additionally, the internal bus supports and insulators that are visible from the inspection hatches will be inspected for structural integrity and signs of cracks.

The staff found that the visual inspection of bus ducts, bus bar, and internal bus supports will provide an indication of aging effects. Additionally, testing of bolted connections and insulation system will provide assurance that bus ducts are not exposed to excessive ohmic or ambient heating.

The staff confirmed that the parameters monitored or inspected program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.1.40, the applicant stated that the detection of aging effects will commence prior to the expiration of the current 40-year license for each unit, and will be conducted at least once every 10 years thereafter throughout the period of extended operation. The staff found that the 10-year inspection frequency is an adequate period to preclude failure of bus ducts because industry experience has shown that the aging degradation is a slow process.

The staff confirmed that the detection of aging effects program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.1.40, the applicant stated that trending is not a required attribute of this program.

The staff confirmed that the monitoring and trending program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.1.40, the applicant stated that phase bus insulation must be free of embrittlement, cracking, melting, discoloration, or other damage; and it must pass the acceptance criteria established for the test being performed. The bus enclosure will be free of unacceptable indications of cracks, corrosion, foreign debris, excessive dust build-up, and evidence of water intrusion. Bolted bus connection splice shall not have any of the following signs:

- For taped connections: tape burning/heating-up, tape cracking, corona effects, or other damage

- For boot type cover splices: "as found" loose connections and arcing damage

- For uninsulated connections: evidence of tracking, corrosion, or ground faults

It shall also pass the acceptance criteria established for the test being performed.

The staff found this to be acceptable since the acceptance criteria are based on the inspections and test acceptance criteria.

The staff confirmed that the acceptance criteria program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - In LRA Section B.2.1.40, the applicant stated that this is a new AMP; therefore, no operating experience exists. In response to the staff's RAI 3.6-4, the applicant stated that both industry and plant-specific experience was reviewed and considered in the program. The staff found that the proposed program will provide assurance that bus ducts are not exposed to excessive ohmic or ambient heating.

The staff confirmed that the operating experience program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

In reviewing the program elements and based on implementation of the Bus Inspection Program, the staff found that there is reasonable assurance that the aging effects of non-segregated phase bus insulation and loosening of fastening hardware associated with isolated and non-segregated phase bus will be adequately managed such that isolated and non-segregated phase bus will continue to perform its intended functions for the period of extended operation.

<u>UFSAR Supplement</u>. In LRA Section A.2.2, the applicant provided the UFSAR supplement for the Bus Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review, RAI response, and audit of the applicant's program, the staff concluded that the applicant had 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 supplements for this AMP and found that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Diesel Starting Air Program

<u>Summary of Technical Information in the Application</u>. The applicant's Diesel Starting Air Program is described in LRA Section B.2.1.41, "Diesel Starting Air Program." In the LRA, the applicant stated that this is an existing plant-specific program.

The Diesel Starting Air Program manages the emergency diesel generator (EDG) starting air system. This program was originally developed in response to plant operating experience with corrosion in the system, and will be enhanced with additional inspections for license renewal. The program includes the preventive actions of replacing filters and desiccant, and inspections of the system components to verify that unacceptable corrosion is not occurring. The Diesel Generator Starting Air Program is credited for managing the loss of material due to general corrosion of carbon, low-alloy, cast iron, and cast-iron alloy components in the diesel generator starting air system (LRA Table 3.3.2.30).

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.1.41, regarding the applicant's demonstration of the Diesel Starting Air Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Diesel Starting Air Program against the AMP elements found in the SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1, and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - In LRA Section B.2.1.41, the applicant stated that the program scope includes the starting air systems for the EDGs. LRA Table 3.3.2.30 shows that the program is used to manage general corrosion of carbon and low-alloy steel, as well as cast iron and cast-iron alloy components in an air/gas internal environment. The components include air-start motors, fittings, piping, strainers, tanks, tubing, and valves.

    The staff confirmed that the scope of the program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.1.41, the applicant stated that the mitigative actions include filter replacement and desiccant replacement. These actions maintain the air quality and thereby reduce corrosion. The staff found that these are appropriate preventive measures for reducing the effects of aging of the EDG air system.

    The staff confirmed that the preventive actions program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - In LRA Section B.2.1.41, the applicant stated that the program provides for periodic inspection of moisture traps, pilot valves, and lift check

valves for corrosion, erosion, pitting, and wear. These inspections are beyond the identified aging effects of the long-lived passive components covered by the scope of the Rule (and included in LRA Table 3.3.2.20), but are acceptable because they will provide early indication of aging that would result from a reduction of air quality, and will address the plant operating experience (see below). The LRA also states that the diesel generator starting air piping and receivers will be inspected for loss of material using the One-Time Inspection Program. The staff considers this an acceptable inspection for confirming that any aging is not significant.

The staff confirmed that the parameters monitored or inspected program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.1.41, the applicant stated that the detection of aging effects is through the periodic visual inspection of the moisture traps, pilot valves, and lift check valves. The inspections are for corrosion, erosion, pitting, and wear. In addition, the LRA states that the One-Time Inspection Program will be used to inspect for loss of material in the emergency diesel starting air system piping and receivers. The staff's review of the One-Time Inspection Program is in SER Section 3.0.3.1.7. The staff found that these are appropriate inspections for the identified aging effects.

The staff confirmed that the detection of aging effects program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.1.41, the applicant stated that this program is implemented through the Preventive Maintenance Program, which includes provisions for monitoring and trending. In addition, failure to meet acceptance criteria will result in corrective actions. The staff found that this is reasonable and acceptable monitoring and trending.

The staff confirmed that the monitoring and trending program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.1.41, the applicant stated that the acceptance criteria are typically qualitative. An example would be “absence of corrosion.” If these criteria are not met, corrective actions result in an evaluation to ensure that the intended functions are maintained. The staff found that performing an evaluation to ensure the intended functions are maintained is an acceptable method of managing aging.

The staff confirmed that the acceptance criteria program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - In LRA Section B.2.1.41, the applicant stated that during the 1980s, the diesel generator air-start system experienced failures of the air-start solenoid valves during a start sequence. The air-start motor did not disengage due to corrosion

debris, which pitted the air solenoid valve seats, preventing the air-start solenoid valves from completely closing. In response, the applicant modified the system by installing air dryers and moisture traps, implemented periodic maintenance including the replacement of filters and desiccant, and verified the effectiveness of the modifications with inspections.

The staff confirmed that the operating experience program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

UFSAR Supplement. In LRA Section A.2.3, the applicant provided the UFSAR supplement for the Diesel Starting Air Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program. The staff found this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's program, the staff determined that the applicant had 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 concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.2.1.13)

Summary of Technical Information in the Application. In its response to RAI 3.1.2.2-9 (see Section 3.1.2.3.17), the applicant determined that this program should be deleted, however, the staff decided to keep the evaluation as follows for the limited program scope.

The Thermal Aging Embrittlement of CASS Program is discussed in LRA Section B.2.1.13. The applicant stated that the only CASS components within the scope of license renewal that were determined to be susceptible to thermal aging embrittlement are the main steam line flow-restricting venturis. The material of the venturis is low-molybdenum with a delta ferrite content of 18.3 percent. The venturis are exposed to a reactor steam environment that is less than 320 °C (610 °F). The applicant stated that, based on evaluation of material and environmental characteristics in accordance with the guidelines of EPRI Technical Report 1000976, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components - January 2001," a Thermal Aging Embrittlement of CASS Program is not required.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program to determine the validity of the applicant's conclusion that a Thermal Aging Embrittlement of CASS Program is not required, and to ensure that the intended function(s) of the components will be maintained consistent with the CLB for the period of extended operation.

CASS exposed to elevated temperatures is subject to thermal aging during service. The effects of thermal aging include increases in tensile and a decrease in fracture toughness. The decrease in fracture toughness is proportional to the level of ferrite in the material. Thermal aging of susceptible materials will continue until a saturation or fully aged point is reached. The staff's position regarding thermal aging of CASS components is detailed in the letter from Christopher Grimes (NRC) to Douglas Waters, (NEI), dated May 19, 2000. In order to determine if the applicant evaluated the CASS components in accordance with the aforementioned letter, the staff requested additional information from the applicant. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.1.13-1, the staff requested that the applicant provide the material specification including material grade, chemical content, casting method, percent ferrite, and operating temperature for the flow-restricting venturis. The staff also requested the applicant to confirm that the flow-restricting venturis had been evaluated in accordance with the above referenced staff letter dated May 19, 2000, and to state if the venturis were potentially susceptible to thermal aging embrittlement when screened using the criteria outlined in the aforementioned letter.

In its response, by letter dated December 9, 2004, the applicant stated that the main steam line flow-restricting venturis are ASTM A 351 Grade CF8. The actual chemistry and casting method are not known by the applicant. The operating temperature of the main steam line is 550 °F, and the applicant calculated the delta ferrite content to be 18.3 percent. Although the applicant does not know the precise chemistry of the components, it used worst-case values for the chemistry range of ASTM A 351 Grade CF8, as listed in the 1975 Annual Book of ASTM Standards, to calculate the delta ferrite content using Hull's equivalent factors in NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems."

Based on the screening criteria listed in Table 2 of the NRC letter dated May 19, 2000, neither statically or centrifugally cast components with a low molybdenum content (0.5 percent max.) and a delta ferrite level less than 20 percent are susceptible to thermal aging embrittlement. The applicant stated in its response to RAI B.2.1.13-1 that the CASS flow-restricting venturis have been evaluated for thermal aging in accordance with the guidance detailed in the May 19, 2000, NRC letter. Based on the applicant's evaluation of the flow-restricting venturis in accordance with the NRC letter, the staff found acceptable the applicant's conclusion that a CASS AMP is not required.

Conclusion. The staff reviewed the information provided in LRA Section B.2.1.13 as supplemented by the applicant's response to the staff's RAI. On the basis of this review, the staff concluded that the applicant had demonstrated that a thermal aging embrittlement of CASS AMP is not required and hence no aging management for Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program, as required by 10 CFR 54.21(a)(3), is required for the only CASS components within the scope of license renewal in the LRA application.

3.0.3.3.5 Unit 1 Periodic Inspection Program (B.2.1.42)

Summary of Technical Information in the Application. In the LRA, the applicant did not include a description of the new, plant-specific AMP B.2.1.42, "Unit 1 Periodic Inspection Program." During the course of the staff's AMR of Unit 1 systems in layup for the extended outage, it was realized that neither the GALL-recommended one-time inspection nor the Unit 1 restart inspection would be sufficient in itself to monitor the effects of any new degradation that will manifest during the period of extended operation. This plant-specific program is designed to monitor the condition of and perform periodic inspections of components that were in layup and have been requalified without replacement. A program description and a history of the program development is described below (see Sections 3.7.1.2 and 3.7.1.3).

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in AMP B.2.1.42 regarding the applicant's demonstration of the Unit 1 Periodic Inspection Program to ensure that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Periodic Inspection Program against the AMP elements found in the SRP-LR Section A.1.2.3 and Table A.1-1, and focused on how the program manages aging effects through the effective incorporation of the 10 program elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

The program was initially submitted for review by TVA letter dated August 4, 2005. The staff review determined that the required information submitted was not entirely complete or consistent with the information identified in SRP-LR Section A.1.2.3. On September 2, 2005, in an informal communication (8 staff questions) and in a formal meeting summary dated October 31, 2005, the staff requested additional information to support their review. The program was revised and resubmitted by TVA letter dated November 16, 2005.

In NRC Question 1, the staff requested the applicant to review the entire SRP-LR Section A.1.2.3 and to include additional applicable information. In NRC Question 2, the staff also identified a general concern that, in the description of the program, the use of the term "failures" is not appropriate for license renewal. In response, the applicant revised the term "failures" to read, "acceptable degradation." The applicant also revised the UFSAR Section A.2.4 and the description of each element to include the information identified in SRP-LR Section A.1.2.3, as discussed below.

(1) Scope of Program - In AMP Section B.2.1.42, the applicant stated that the program provides periodic monitoring of the non-replaced piping/fittings that were not in service supporting operation of Units 2 and 3. This piping is carbon/low-alloy or stainless steel that was exposed to air, treated water, or raw water during the extended Unit 1 shutdown. The susceptible locations identified are those areas determined to have the highest potential for service-induced wear or latent aging effects. The staff found, in general, the scope of the program to be comprehensive and acceptable because it includes components that were subject to lay-up at locations most susceptible to degradation as a result of the extended outage. The applicant's response to Question 3, letter dated November 16, 2005 revision, did not include a detailed AMR table (Table 3) in a standard format. The format should include listing of system and components, and specify reference to the new Inspection program, "B.2.1.42 Unit 1 Periodic Inspection

Program." as the AMP. This did not allow a staff review of specific combinations of components, materials, environments and aging effects to be managed by the new Unit 1 Periodic Inspection Program. In addition, the applicant did not respond to NRC Question 3(b) concerning the number of sample locations. Instead, the applicant stated that its earlier response, dated May 18, 2005, in a table titled,"NDE Examinations Performed for Original Non-replaced Piping, (3 sheets)," had identified specific components, piping, and welds that will be included in the scope of this new program. The applicant stated that the table included piping and welds in the RHRSW, Fire protection, EECW, RCW, CRD, CS, FW, HPCI, MS, RCIC, RHR, and RBCCW systems. The staff accepts this list to satisfy the requirement of the program element "scope" in lieu of the detailed AMR table for purpose of this evaluation. However, in a teleconference with the applicant on December 7, 2005, the applicant agreed (letter dated December 20, 2005) to perform a revision of the LRA AMR Tables (Table 3) to add the newly identified piping and components that will be included in the scope of the program and identify these in appropriate systems tables in a future revision. Also, the applicant agreed to review the adequacy of the number of sample locations on the basis of a 95/95 confidence level.

The staff confirmed that the scope of the program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that the program attribute is acceptable.

(2) Preventive Actions - In the initial program Element 2, the applicant identified the Unit 1 Periodic Inspection Program as a detection program. Programs are normally identified as condition monitoring, performance monitoring, or prevention and mitigation programs. In NRC Question 5, the staff requested the applicant to clarify that the program is a condition monitoring program. In the revised AMP Section B.2.1.42, the applicant stated that the program is a condition monitoring program and, thus, there are no preventive actions. The staff concurred with this assessment and does not identify the need for any preventive actions associated with this program.

The staff confirmed that the preventive actions program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that the program attribute is acceptable.

(3) Parameters Monitored or Inspected - In AMP Section B.2.1.42, the applicant clarified that the Unit 1 Periodic Inspection Program is a condition monitoring program and only the first two items of the SRP-LR are applicable. The applicant identified that the selected sample will be examined by the same or equivalent, methodology (UT thickness for piping and UT shear wave and surface exam for weld), as performed to determine acceptability of not replacing piping sections prior to restart. The applicant stated that the susceptible locations were those areas determined to have the highest potential for service-induced wear or latent aging effects, which includes all types of corrosion. The applicant also identified that the inspection techniques utilized evaluate internal conditions and are sensitive to the presence of unacceptable conditions, including wear, erosion, corrosion (including crevice corrosion) if present. In addition, the applicant initially identified that the sample selected for periodic inspection will be based on a 90/90 confidence level consistent with the methodology identified in EPRI 107514. The staff was concerned that a 90/90 confidence level may not be appropriate

and that EPRI 107514 had not been reviewed by the staff. In NRC Question 4, the staff requested the applicant to clarify whether application of EPRI 107514 represented an industry consensus for selecting a sample on the basis of 90/90 criteria. The applicant was also requested to identify the sample size on the basis of 90/90 criteria versus 95/95 and to justify selecting a sample size on the basis of the 90/90 criteria versus the more restrictive 95/95 criteria. In its response, dated November 16, 2005, the applicant revised the sample size basis to reflect a confidence level of 95/95 and replaced the EPRI reference with “Elementary Statistical Analysis.” The staff’s review of the acceptability of the revised basis for the sample size is further discussed under Element 4. The staff found that the parameters monitored or inspected will provide symptomatic evidence of potential degradation and, therefore, are acceptable.

The staff confirmed that the parameters monitored or inspected program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - SRP Section A.1.2.3.4 states that the applicant is to provide justification, including codes and standards referenced, that the inspection technique and frequency are adequate to detect the aging effects before a loss of SC intended function**.** In the initial submittal of AMP B.2.1.42, the applicant did not identify any codes and standards. In NRC Question 6, the staff requested the applicant to include additional information to demonstrate that the technique and frequency of future inspections is justified. In revised AMP Section B.2.1.42, in its submittal dated November 16, 2005, the applicant stated that the program is not covered by industry codes or standards and the selected inspection methodologies are based on the inspections performed to determine whether components require replacement prior to restart. The applicant also stated that the examination techniques utilized for the baseline inspection were ultrasonic thickness measurements for the piping and ultrasonic shear wave for welds. The applicant identified that the restart inspections can be used as a baseline and additional periodic inspections of sample locations will be performed after Unit 1 is returned to service and again within the first ten years of the period of extended operation. The use of ultrasonic thickness measurements and ultrasonic shear wave techniques should be capable of detecting most forms of internal degradation of the piping and welds caused by the extended outage. The staff was concerned that inspections may not be performed to recognized codes and standards and UT inspection may not be the best technique to detect certain types of corrosion. The staff believes that codes and standards such as ASME Section V and ASTM, are appropriate references. Based on industry standards such as ASTM G46-94 and standard practices identified in EPRI documents and the GALL Report, visual inspections may be a more appropriate technique to identify certain types of internal degradation, such as pitting and MIC. Therefore, the applicant was requested to identify specific codes and standards used for periodic inspections and evaluate the acceptability of UT alone to detect all forms of corrosion. In a teleconference with the applicant on December 7, 2005 (applicant submittal dated December 20, 2005) the applicant indicated that internal visual inspections are performed as part of other aging management programs when the system is open, but UT is preferred for periodic inspection trending purposes, since opportunistic internal inspections are limited by accessibility. The applicant stated that it will also perform suitable trending for

degradations that could appear during the extended operation, and will apply BFN's Corrective Action Program including appropriate mitigative action if any degradation could lead to loss of intended function. The staff found that a combination of opportunistic internal visual inspections combined with periodic UT inspections to be acceptable techniques to detect latent aging effects.

In regard to the basis for the sample size addressed in the SRP-LR "Detection of Aging Effects" element, the applicant described the sample size basis under Element 3, "Parameters Monitored or Inspected." The applicant applied a statistical analysis to establish a confidence level of 95/95 for selecting a sample size within a common material and environment. In SER Section A.2.4, submitted by letter dated October 19, 2005, the applicant stated that if unacceptable degradation is identified, the sample size will be appropriately expanded. Although the applicant did not respond to staff's request in NRC Question 3(b) concerning the number of sample locations (scope) to be inspected, the applicant did adequately identify the basis for the sample size.

The staff concurred that application of periodic internal visual and ultrasonic inspections are acceptable to detect that aging effects may be occurred during the extended outage.

The staff found that the 95/95 confidence level is an acceptable basis for determining an adequate sample size and that a provision to expand the sample size is consistent with industry practice and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In the initial submittal of AMP B.2.1.42, the applicant did not identify if results will be monitored and trended. In NRC question 7, the staff requested the applicant to clarify that results will be monitored and trended. In its response, the applicant confirmed that the program has been revised to clarify the requirement to monitor and trend the results of periodic inspections. In revised AMP Section B.2.1.42, the applicant stated that the inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. SRP-LR Section A.1.2.3.5 states that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The staff found that the overall monitoring and trending proposed by the applicant are acceptable because there is reasonable assurance that effective periodic inspections combined with the Corrective Action Program will effectively manage the applicable aging effects.

The staff confirmed that the monitoring and trending program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In AMP Section B.2.1.42, the applicant stated that the acceptance criteria is that the pipe wall will remain above minimum acceptable wall thickness until the next periodic inspection, and that no unacceptable weld cracks exist. The staff found that the application of minimum wall thickness and no unacceptable weld cracks based on the Code of record to be reasonable and appropriate acceptance criteria to maintain the intended functions of the components inspected.

The staff confirmed that the acceptance criteria program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - In NRC Question 8 of the informal staff request of September 2, 2005, the staff requested the applicant to identify a commitment to provide (or have available for review) operating experience for this new program in the future to confirm its effectiveness. The applicant's response confirmed that the program has been revised to clarify the requirement to evaluate the results of the periodic inspections to verify program effectiveness. In the revised version of AMP Section B.2.1.42, the applicant stated that the Unit 1 Periodic Inspection Program is a new program that will monitor the operating conditions of Unit 1 components that were not replaced during the Unit 1 restart. The applicant credits the trending data developed in Element 5 to demonstrate the effectiveness of the Unit 1 Periodic Inspection Program. The staff found that there is reasonable assurance that the use of trending data will provide objective evidence to determine the effectiveness of the periodic inspection program.

The staff confirmed that the operating experience program element satisfies the criterion defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

UFSAR Supplement. By letter dated November 16, 2005, the applicant provided the following UFSAR supplement for the Unit 1 Periodic Inspection Program:

> The Unit 1 Periodic Inspection Program is a new program that performs periodic inspections of the non-replaced piping/fittings that were not in service supporting operation of Units 2 and 3 following the extended Unit 1 outage to verify that no latent aging effects are occurring, and to correct degraded conditions prior to loss of function.
>
> During the Unit 1 restart project, examinations were performed to verify acceptability of the existing piping that was not replaced. The specific examinations are discussed in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) – Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005. This piping is carbon/low-alloy or stainless steel that was exposed to air, treated water, or raw water during the extended Unit 1 shutdown. The Unit 1 Periodic Inspection Program will examine a sample of those locations examined for plant restart as discussed in the referenced letter to verify that no latent aging effects are occurring. The sample size will be determined in accordance with the sampling methodology described in S. S. Wilks, "Elementary Statistical Analysis," Princeton University Press, 1948. If unacceptable degradation is identified, the sample size will be appropriately expanded. The initial sample, once selected, will be utilized in subsequent inspections, if practical.
>
> These periodic inspections are in addition to the restart inspections performed prior to Unit 1 restart. The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation. The susceptible locations identified are those areas determined to have the highest potential for service-induced wear or latent aging effects. The inspection

techniques utilized evaluate internal conditions that are sensitive to the presence of unacceptable conditions including wear, erosion, and corrosion (including crevice corrosion) if present. For these locations, the restart inspections can be utilized as a baseline for comparison.

The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation and prior to the end of the current operating period. The second periodic inspection of all sample locations will be completed within the first ten E2-9 years of the period of extended operation. The inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. The inspections will continue until the trend of the results provides a basis to discontinue the inspections.

The staff reviewed the above UFSAR supplement and determined that it provides an adequate summary description of the program. The staff found that this section of the UFSAR supplement met the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's program, the staff found that the Unit 1 Periodic Inspection Program adequately addresses the 10 program elements identified in Appendix A of 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 aging management program and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. SRP-LR, Branch Technical Position RLSB-1, "Aging Management Review - Generic," describes ten attributes of an acceptable AMP. Three of these ten attributes are associated with the quality assurance activities of corrective action, confirmation processes, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of Branch Technical Position 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.

SRP-LR, Branch Technical Position IQMB-1, "Quality Assurance For Aging Management Programs," noted that those aspects of the AMP that affect quality of SR SSCs are subject to the quality assurance (QA) requirements of 10 CFR Part 50, Appendix B. Additionally, for NSR SCs subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used by the applicant to address the elements of corrective action, the confirmation process, and administrative controls. Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

- SR structures and components are subject to 10 CFR Part 50, Appendix B, requirements, which are adequate to address all quality-related aspects of an AMP consistent with the CLB of the facility for the period of extended operation.
- For NSR SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50 Appendix B program to include these structures and components 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

LRA Section 3.0, "Aging Management Review Results," provides an AMR summary for each unique structure, component, or commodity group at Units 2 and 3, (Unit 1 is in an extended outage) determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management and AMPs utilized to manage these aging effects. LRA Appendix A, "UFSAR Supplement," and Appendix B, "Aging Management Program Descriptions," demonstrate how the identified programs manage aging effects using attributes consistent with the industry and staff guidance. In LRA Appendix A, the applicant does not commit that the QA Program includes the elements of corrective action, confirmation process, and administrative controls or that it is applicable to both SR and NSR SSCs that are within the scope of license renewal. However, in LRA Section B.1.3, “Quality Assurance and Administrative Controls," in "Aging Management Program Descriptions," the applicant stated that the QA Program implements the requirements of 10 CFR Part 50, Appendix B, and is consistent with the summary in SRP-LR Appendix A.2 (Reference B-1). The QA Program includes the elements of corrective action, confirmation process, and administrative control, and it is applicable to the SR and NSR SSCs that are subject to an AMR. In many cases, existing programs were found to be adequate for managing aging effects during the period of extended operation. Generically, the three elements are applicable as follows:

Corrective Action. A single corrective action process is applied regardless of the safety classification of the structure or component. Corrective actions are implemented through the initiation of a Problem Evaluation Report (PER) in accordance with the applicant’s nuclear procedure established to implement the provisions of 10 CFR Part 50 Appendix B. Plant procedures require the initiation of a PER to document actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss. Site procedures that implement aging management activities for license renewal require that a PER be prepared whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). Equipment deficiencies are corrected through the initiation of a work order in accordance with plant procedures. Although equipment deficiencies may initially be documented by a work order, the corrective action process specifies that a PER also be initiated if required.

Confirmation Process. The confirmation process ensures that follow-up actions are taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting the adverse conditions and precluding their recurrence. Relevant applicant procedures include provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate. The procedure requires determinations. The corrective action process also requires monitoring for potentially adverse trends. A PER is required if adverse trends persist. Since the same 10 CFR 50, Appendix B, corrective action and confirmation process is applied for nonconforming SR and NSR SCs subject to AMR for license renewal, the Corrective Action Program is consistent with the GALL Report.

Administrative Controls. AMPs are administered through various plant implementation documents, which are subject to administrative controls, including a formal review and approval process in accordance with the requirements of 10 CFR Part 50, Appendix B, and, therefore are consistent with SRP-LR.

3.0.4.2 Staff Evaluation

The staff reviewed the applicant's QA controls for AMPs as described in the LRA. The purpose of this review was to assure that the aging management activities were consistent with the staff's guidance described in SRP-LR, Section A.2, "Quality Assurance for AMPs (Branch Technical Position IQMB-1)," regarding QA attributes of AMPs. Based on the staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their quality attributes provided in LRA Appendix B.1.3 are consistent with the staff's position regarding QA for aging management. In particular, the applicant noted that its QA Program provides elements of corrective action, confirmation processes, and administrative controls for both SR and NSR SSCs. However, the applicant did not describe the use of the QA Program and its associated attributes in LRA Appendix A, "UFSAR" Appendix A. Specifically, consistent with Branch Technical Position IQMB-1, the applicant should either document a commitment to expand the scope of its 10 CFR Part 50 Appendix B program to include NSR SCs subject to an AMP to address the AMP quality attributes during the period of extended operation, or propose an alternate means to address this issue. In RAI 2.1-3. dated July 30, 2004, the staff requested the applicant to clarify its position with regard to the quality attributes of AMPs in LRA Appendix A. By letter dated September 3, 2004, the applicant responded as follows:

The following statement supplements LRA Appendix A.1, "Aging Management Programs:"

> The integrated plant assessment for license renewal identified new programs, enhancements to existing programs, and existing programs necessary to continue operation of BFN Units 1, 2, and 3 during the additional twenty years beyond the initial license term. This chapter describes those programs. The TVA Nuclear Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B. The TVA Nuclear Quality Assurance Program includes elements of corrective action, confirmation process, and administrative controls. These elements are applicable to all aging management programs credited for license renewal. The Corrective Action Program ensures corrective actions, including root cause determinations and prevention of recurrence are timely. The Corrective Action Program also includes the confirmation process that ensures preventive actions are adequate and that appropriate corrective actions have been complete and are effective. Administrative controls provide for a formal review and approval process of program implementing documents.

The staff reviewed the statement and requested that the applicant revise the statement made in its September 24, 2004, response to explicitly state that the applicant's 10 CFR Part 50,

Appendix B, Quality Assurance Program will apply to both SR and NSR SSCs within the scope of license renewal and subject to one or more of the AMPs.

By letter dated October 18, 2004, the applicant provided a supplemental response, which stated, in part, that the elements (corrective action, confirmation process, and administrative controls) are applicable to all AMPs, SSCs, systems, and components. The staff reviewed the revised response and finds that it adequately addresses the staff's concerns regarding application of the AMPs to both SR and NSR SSCs within the scope of license renewal and subject to one or more of the AMPs, and is, therefore, acceptable. The staff considered the information provided by the applicant acceptable and the staff’s concern described in RAI 2.1-3 is resolved.

3.0.4.3 Conclusion

The staff found 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 SR and NSR SSCs within the scope of license renewal and stated that 10 CFR Part 50 Appendix B provides corrective actions, confirmation processes, and administrative controls. Therefore, the applicant’s QA description for its AMPs is acceptable.

3.1 <u>Aging Management Review of Reactor Vessel, Internals, and Reactor Coolant System</u>

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and reactor coolant system components and component groups associated with the following systems:

- reactor vessel
- reactor vessel internals
- reactor vessel vents and drains
- reactor recirculation

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.1, the applicant provided AMR results for components. In LRA Table 3.1.1, "Summary of Aging Management Review Evaluations for 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, and reactor coolant system components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and reactor coolant system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs during the weeks of June 21 and July 26, 2004, to confirm the applicant's claim that certain identified AMRs were consistent with 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 had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.1.2.1.

In the onsite audit, the staff also selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.1.2.2. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.1.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects were identified and evaluating whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.1.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.1.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the reactor vessel, internals, and reactor coolant system components.

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 in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor coolant pressure boundary components (Item Number 3.1.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Isolation condenser (Item Number 3.1.1.3)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection Program; Water Chemistry Program	N/A	Not applicable BFN does not have isolation condenser The isolation condenser function is performed by the RCIC system
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 of 10 CFR 50 and RG 1.99	Reactor Vessel Surveillance Program TLAA	Consistent with GALL which recommends further evaluation (See Section 3.1.2.2.3) This TLAA is evaluated in Section 4.2, Neutron Embrittlement of Reactor Vessel and Internals

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor vessel beltline shell and welds (Item Number 3.1.1.5)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance Program	Reactor Vessel Surveillance Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.2.3)
Small-bore reactor coolant system and connected systems piping (Item Number 3.1.1.7)	Crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), and thermal and mechanical loading	Inservice Inspection Program; Water Chemistry Program; One-Time inspection Program	Inservice Inspection Program; Chemistry Control Program; One-Time inspection Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.2.4)
Jet pump sensing line and reactor vessel flange leak detection line (Item Number 3.1.1.8)	Crack initiation and growth due to SCC, IGSCC, or cyclic loading	Plant-specific	Stress Corrosion Cracking Program; Inservice Inspection Program; Chemistry Control Program; One-Time Inspection Program	See Section 3.1.2.3.6
Isolation condenser (Item Number 3.1.1.9)	Crack initiation and growth due to SCC or cyclic loading	Inservice Inspection Program; Water Chemistry Program	N/A	Not applicable BFN does not have isolation condenser The isolation condenser function is performed by the RCIC system (See Section 3.1.2.2.4)
Reactor vessel closure studs and stud assembly (Item Number 3.1.1.22)	Crack initiation and growth due to SCC an/or IGSCC	Reactor Head Closure Studs Program	Reactor Head Closure Studs Program	Consistent with GALL which recommends no further evaluation (See Section 3.1.2.1.12)
CASS pump casing and valve body (Item Number 3.1.1.23)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection Program	Inservice Inspection Program	Consistent with GALL which recommends no further evaluation (See Section 3.1.2.3.17)
CASS piping (Item Number 3.1.1.24)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS Program	N/A	Not applicable No RCPB CASS piping and fittings are used in BFN (See Section 3.1.2.3.17)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
BWR piping and fittings; steam generator components (Item Number 3.1.1.25)	Wall thinning due to flow accelerated corrosion	Flow Accelerated Corrosion Program	Flow Accelerated Corrosion Program	Consistent with GALL which recommends no further evaluation (See Section 3.1.2.2.12)
Reactor coolant pressure boundary (RCPB) valve closure bolting, manway and holding bolting, 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; and crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity Program	Bolting Integrity Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.4)
Feedwater and control rod drive (CRD) return line nozzles (Item Number 3.1.1.27)	Crack initiation and growth due to cyclic loading	Feedwater Nozzle Program; CRD Return Line Nozzle Program	Feedwater Nozzle Program; CRD Return Line Nozzle Program	Consistent with GALL which recommends no further evaluation (See Sections 3.1.2.2.4, 3.1.2.3.9)
Vessel shell attachment welds (Item Number 3.1.1.28)	Crack initiation and growth due to SCC and/or IGSCC	BWR Vessel ID Attachment Welds Program; Water Chemistry Program	BWR Vessel ID Attachment Welds Program; Chemistry Control Program	Consistent with GALL with exceptions (See Section 3.1.2.3.7)
Nozzle safe ends, recirculation pump casing, connected systems piping and fittings, body and bonnet of valves (Item Number 3.1.1.29)	Crack initiation and growth due to SCC and/or IGSCC	BWR Stress Corrosion Cracking Program; Water Chemistry Program	BWR Stress Corrosion Cracking Program; Chemistry Control Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.8)
Penetrations (Item Number 3.1.1.30)	Crack initiation and growth due to SCC, IGSCC, and/or cyclic loading	BWR Bottom Head Penetrations Program; Water Chemistry Program	BWR Bottom Head Penetrations Program; Chemistry Control Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.11)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Core shroud and core plate, support structure, top guide, core spray lines and spargers, jet pump assemblies, control rod drive housing, nuclear instrument guide tubes (Item Number 3.1.1.31)	Crack initiation and growth due to SCC, IGSCC, and/or irradiation assisted stress corrosion cracking (IASCC)	BWR Vessel Internals Program; Water Chemistry Program	BWR Vessel Internals Program; Chemistry Control Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.16)
Core shroud and core plate access hole cover (welded and mechanical covres) (Item Number 3.1.1.32)	Crack initiation and growth due to SCC, IGSCC, and/or IASCC	ASME Section XI Inservice Inspection Program; Water Chemistry Program	ASME Section XI Inservice Inspection Program; Chemistry Control Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.2)
Jet pump assembly castings and orificed fuel support (Item Number 3.1.1.33)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement	N/A	Not required for BFN (See Section 3.1.2.3.17)
Unclad top head and nozzles (Item Number 3.1.1.34)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection Program; Water Chemistry Program	Inservice Inspection Program; Chemistry Control Program	Consistent with GALL which recommends further evaluation (See Section 3.1.2.3.18)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.1.2.1, involves the staff's review of the AMR results for components in the reactor vessel, internals, and reactor coolant system that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.1.2.2, involves the staff's review of the AMR results for components in the reactor vessel, internals, and reactor coolant system that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, involves the staff's review of the AMR results for components in the reactor vessel, internals, and reactor coolant system that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the reactor vessel, internals, and reactor coolant system components is documented in SER Section 3.0.3.

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 LRA Section 3.1.2.1, 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, and reactor coolant system components:

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program
- BWR Control Rod Drive Return Line Nozzle Program
- BWR Feedwater Nozzle Program
- BWR Penetrations Program
- BWR Vessel ID Attachment Welds Program
- BWR Stress Corrosion Cracking Program
- Chemistry Control Program
- One-time Inspection Program
- Reactor Head Closure Studs Program
- Reactor Vessel Surveillance Program
- BWR Vessel Internals Program
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program
- Bolting Integrity Program
- Flow-Accelerated Corrosion Program
- Systems Monitoring Program
- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program

Staff Evaluation. In LRA Tables 3.1.2-1 through 3.1.2-4, the applicant provided a summary of AMRs for the reactor vessel, internals, and reactor coolant 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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 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 had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated 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 was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in its BFN audit and review 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 had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its audit of the LRA to determine if the applicant's reference to the GALL Report is acceptable.

The staff reviewed the LRA to confirm that the applicant: (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects had been reviewed and are evaluated in the GALL Report, and (3) identified those aging effects for the reactor vessel, internals, and RCS system components that are subject to an AMR.

A review of the Table 2s identified the following issues:

The staff identified that LRA Table 3.1.2.2 presents the AMR for the reactor vessel internals core shroud and core plate (row 1). The corresponding GALL Report Item IV.B1.1-d indicates that the access hole cover (AHC) welds would require an augmented inspection (UT or other demonstrated acceptable inspection) to manage crack initiation due to SCC in the crevice regions of the access hole covers which are not amenable to visual inspections. This issue has been addressed in GE Service Information Letter (SIL) 462 (1988) after circumferential SCC was found in a creviced AHC fabricated from nickel alloy 600. BFN Technical Justification Number TJ-2004-02, dated 3-02-2004, provides justification for variance from GE SIL 462, revision 1, that provides guidance on inspection of core shroud AHCs. BFN has implemented the GE SIL requirements for Units 2 and 3, and they will be applicable to all three units upon re-start of Unit 1. Details of AHC replacements are provided in RAI 3.1.2-6(A) response, by letter dated January 31, 2005 and May 25, 2005, respectively. The staff found this acceptable.

The staff identified that LRA Table 3.1.2.2, is not consistent with the GALL Report, Item IVB1.4-d, and asked the applicant for an explanation. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the GALL Report item should have been IVB1.6-a instead of IVB1.4-d and the table will be corrected. The staff found this acceptable because it is consistent with the GALL Report.

LRA Table 3.1.2.3, row 51, presents the AMR for the stainless steel valves in treated water internal environment for the reactor vessel vents and drains systems. The staff identified a difference in crediting AMPs for this commodity group. The table includes the Chemistry Control Program, BWR Stress Corrosion Cracking Program, and One-Time Inspection Program to manage crack initiation and growth due to SCC, and cross-references LRA Table 3.1.1, Item 3.1.1.29. However, LRA Table 3.1.1, Item 3.1.1.29, does not specify the One-Time Inspection Program. During the onsite audit, the staff asked the applicant to explain this difference. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the One-Time Inspection Program will be removed from LRA Table 3.1.2.3, row 51. The staff found this acceptable because it is consistent with the GALL Report.

LRA Table 3.1.2.4, row 48, presents the AMR for the stainless steel fittings, including flow restrictors, in treated water internal environment for the reactor recirculation system. The staff identified a difference in crediting AMPs for this commodity group. The table does not identify the Chemistry Control Program to manage crack initiation and growth due to SCC. However, the referenced GALL Report Item IV.C1.1-l identified the Chemistry Control Program. During the onsite audit, the staff asked the applicant to explain this difference. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Chemistry Control Program will be added to LRA Table 3.1.2.4, row 48. The staff found this acceptable because it is consistent with the GALL Report.

On the basis of its audit, the staff determined that for 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.

<u>Conclusion</u>. The staff evaluated 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 concluded 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 concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

For some line items in LRA Tables 3.1.2.1 through 3.1.2.4 that are identified to be consistent with the GALL Report, the applicant cross-referenced specific line items in LRA Tables 3.1.1 through 3.4.1, for which the GALL Report recommends further evaluation. Where the GALL Report recommends further evaluation, the staff reviewed the applicable further evaluations provided in LRA Sections 3.1.2.2, 3.2.2.2, 3.3.2.2, and 3.4.2.2 against the criteria provided in SRP-LR Sections 3.1.2.2, 3.2.2.2, 3.3.2.2, and 3.4.2.2, respectively. The following provides the staff's assessment of the applicant's further evaluations applicable to the reactor vessel, internals, and reactor coolant system.

Summary of Technical Information in the Application. In LRA Section 3.1.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the reactor vessel, internals, and reactor coolant system components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage (3.1.2.2.1)
- loss of material due to general corrosion (3.1.2.2.2)
- loss of fracture toughness due to neutron irradiation embrittlement (3.1.2.2.3)
- crack initiation and growth due to thermal and mechanical loading or stress corrosion cracking (3.1.2.2.4)
- crack growth due to cyclic loading (3.1.2.2.5, PWR only)
- changes in dimension due to void swelling (3.1.2.2.6/PWR only)
- crack initiation and growth due to stress corrosion cracking or primary water stress corrosion cracking (PWSCC)(3.1.2.2.7/PWR only)
- crack initiation and growth due to stress corrosion cracking or irradiation assisted stress corrosion cracking(3.1.2.2.8/ PWR only)(3.1.2.2.8/PWR only)
- loss of preload due to stress relaxation(3.1.2.2.9/PWR only)
- loss of section thickness due to erosion (3.1.2.2.10/PWR only)
- crack initiation and growth due to PWSCC, 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 (3.1.2.2.11/PWR)
- loss of section thickness due to flow-accelerated corrosion (3.1.2.2.12/PWR)

- ligament cracking due to corrosion (3.1.2.2.13/PWR)
- loss of material due to flow accelerated corrosion (3.1.2.2.14/PWR)
- quality assurance for aging management of non-safety-related components

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 audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.1.2.2 of the SRP-LR. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.1.2.2.1 Cumulative Fatigue Damage

For LRA Table 3.1.1, item 3.1.1.1, the applicant references LRA Section 3.1.2.2.1. This is a TLAA, and is evaluated in SER Section 4.

3.1.2.2.2 Loss of Material due to General Corrosion

The staff reviewed LRA Section 3.1.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.

The SRP-LR identifies that the only BWR component covered by this further evaluation is the isolation condenser. This is not applicable because BFN does not have an isolation condenser.

3.1.2.2.3 Loss of Fracture Toughness Due To Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the criteria in SRP-LR Section 3.1.2.2.3.

Consistent with the SRP-LR, the applicant references LRA Section 4.2. This is a TLAA, and is evaluated in SER Section 4.

Also consistent with the SRP-LR, the applicant references the Reactor Vessel Surveillance Program, described in LRA Section B.2.1.28. This AMP is reviewed and evaluated in SER Section 3.0.3.2.19.

The AMP recommended by the GALL Report for managing loss of fracture toughness due to neutron irradiation embrittlement of the RV is GALL AMP XI.M31, "RV Surveillance," which complies with the requirements of 10 CFR Part 50, Appendices G and H. Loss of fracture toughness due to neutron irradiation embrittlement could occur in the RV. An RV materials surveillance program monitors neutron irradiation embrittlement of the RV. RV surveillance programs may be plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels or may be an ISP based on the criteria in 10 CFR Part 50, Appendix H. In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation.

LRA Section 3.1.2.2.3 addresses (1) loss of fracture toughness due to neutron irradiation embrittlement for ferritic materials that have a neutron fluence of greater than 10^{17} n/cm^2 at the end of the license renewal term, and (2) loss of fracture toughness due to irradiation embrittlement of the RV beltline material. Loss of fracture toughness due to neutron irradiation embrittlement for ferritic materials that have a neutron fluence of greater than 101^{7} n/cm^2 at the end of the license renewal term is a TLAA, and the staff's review of the applicant's evaluation of this TLAA is documented in LRA Section 4.2. In performing this review, the staff followed the guidance in SRP-LR Section 4.2.

The RV Surveillance Program is mandated by 10 CFR Part 50, Appendix H. The RV Surveillance Program is an ISP in accordance with 10 CFR Part 50, Appendix H Paragraph III.C that is based on requirements established by the BWRVIP. Referencing of BWRVIP activities for license renewal was approved by the staff in its SER regarding BWRVIP-74 of October 18, 2001. The demonstration of compliance with the required actions of the SE is summarized in LRA Section 3.1.2.2.16. The applicant stated that the RV Surveillance Program, as supported by associated TLAA evaluations (LRA Section 4.2), will manage loss of fracture toughness of RV beltline components due to irradiation embrittlement by addressing the limiting RV beltline shells and welds.

The applicant also stated that the RV Surveillance Program is described in UFSAR Section 4.2.6 and is based on BWRVIP-78, "BWR Vessel Integrated Surveillance Program Plan," and BWRVIP-86, BWR Vessel and Internal Project Updated BWR Integrated Surveillance Program (ISP) Implementation Plan." Use of the BWRVIP-78 and BWRVIP-86 to address a 40-year license period was approved for referencing in the staff's SER dated February 1, 2000. Use of the BWRVIP ISP for Units 2 and 3 was approved by the staff in its SER dated January 28, 2003. The technical criteria specified in the BWRVIP-78 and BWRVIP-86 were incorporated in the BWRVIP-116, "BWR Vessel and Internals Project-Integrated Surveillance Program (ISP)-Implementation for License Renewal." BWRVIP-116 extends the ISP to cover the BWR fleet through an extended period of operation for all units. The applicant committed to implement the requirements of BWRVIP-116, when approved, for all three RVs. Therefore, the applicant did not submit a plant-specific program in its LRA. The details of the staff's review of this aging effect are included in SER Section 3.0.3.2.

The applicant stated that it will implement the BWRVIP ISP for the period of extended operation, if approved by the staff for the BWR fleet, as applicable to each RV and will request the approval from the staff, if necessary, to use the program at applicable RVs for the period of extended operation. This enhancement is scheduled for completion prior to the period of extended operation.

The staff found that by implementing the ISP program as dictated by the RV Surveillance Program, the applicant demonstrated that it complies with all the recommendations specified in GALL AMP XI.M31. Therefore, the staff accepted the implementation of the RV Surveillance Program for managing the aging effect due to loss of fracture toughness due to neutron irradiation embrittlement of the RVs.

Conclusion. On the basis of its review, the staff found that the applicant appropriately evaluated AMR results involving management of loss of fracture toughness due to neutron irradiation embrittlement as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff found that the applicant had 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).

3.1.2.2.4 Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

LRA Table 3.1.2.3 and Table 3.1.2.4 present the AMRs for small bore piping and fittings (including flow restrictors) less than NPS 4 in treated-water environment for the RCS. These AMRs reference LRA Table 1 Item 3.1.1.7, which references LRA Section 3.1.2.2.4 for the further evaluation.

In the LRA Section 3.1.2.2.4, the applicant addressed the potential for crack initiation and growth due to thermal and mechanical loading or SCC (including IGSCC) that could occur in small-bore RCS and connected system piping less than NPS 4.

SRP-LR Section 3.1.2.2.4 applicable to BFN (BWRs) states the following:

1. Crack initiation and growth due to thermal and mechanical loading or SCC (including IGSCC) could occur in small-bore reactor coolant system and connected system piping less than NPS 4. The existing program relies on ASME Section XI ISI and on control of water chemistry to mitigate SCC. The GALL Report recommends that a plant-specific destructive examination or a nondestructive examination (NDE) that permits inspection of the inside surfaces of the piping be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the extended period. The AMPs should be augmented by verifying that service-induced weld cracking is not occurring in the small-bore piping less than NPS 4, including pipe, fittings, and branch connections. A one-time inspection of a sample of locations is an acceptable method to ensure that the aging effect is not occurring and the component’s intended function will be maintained during the period of extended operation.
2. Crack initiation and growth due to thermal and mechanical loading or SCC (including IGSCC) could occur in BWR reactor vessel flange leak detection line and BWR jet pump sensing line. The GALL Report recommends that a plant-specific AMP be evaluated to mitigate or detect crack initiation and growth due to SCC of vessel flange leak detection line. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of this standard review plan).

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 the component’s intended function will be maintained during the period of extended operation. Per 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 BFN-proposed One-Time Inspection Program includes volumetric examination of a sample of susceptible locations in small bore piping and pipe fittings. During the onsite audit, which took place the weeks of June 21 and July 26, 2004, the staff asked the applicant to explain the selection criteria for these sample locations. In its response, the applicant stated:

> The one-time inspections utilized to verify the effectiveness of the Chemistry Control Program for preventing loss of material will select the susceptible locations based on plant operating experience, with an emphasis on locations that potentially have low or stagnant flow conditions.

The staff expanded the question in a subsequent teleconference with the applicant. In response, the applicant stated:

> The BFN One-Time Inspection Program includes a sample inspection of Reactor Coolant Pressure (RCPB) Boundary piping less than four inch NPS exposed to reactor coolant for cracking.
>
> The Browns Ferry One-Time Inspection Program provides the following description of how cracking will be detected.
>
>> The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small-bore piping, actual inspection locations are based on physical accessibility, exposure levels, NDE techniques, and locations identified in Nuclear Regulatory Commission (NRC) Information Notice (IN) 97-46.
>>
>> Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. For small-bore piping less than NPS 4 in., including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred. Follow-up of unacceptable inspection findings includes expansion of the inspection sample size and locations.
>>
>> The inspection and test techniques prescribed by the program verify any aging effects because these techniques, used by qualified personnel, have been proven effective and consistent with staff expectations. With respect to inspection timing, the one-time inspection is to be completed before the end of the current operating license. The applicant may schedule the inspection in such a way as to minimize the impact on plant operations. However, the inspection is not to be scheduled too early in the current operating term, which could raise questions regarding continued absence of aging effects prior to and near the extended period of operation.

In its letter, dated October 8, 2004, in response to the staff’s question, the applicant stated:

> ... Aging Management Program XI.M32, One-Time Inspection, Evaluation and Technical Basis Section, Detection of Aging Effects, states:

> Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. For small-bore piping less than NPS 4 in., including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred.

As noted from this paragraph, either destructive examination or NDE that is capable of detecting inside surface cracking is required. Since there are UT-inspectable, full penetration butt welds within scope of license renewal, BFN has chosen the second method for our program and no destructive examination of socket welds will be performed. Once this inspection methodology was selected, the possible sample population is full penetration butt welds. BFN has no identified butt welds in ASME Class 1 piping 1-inch NPS and less. Therefore, 1-inch NPS and less piping will not be selected for small-bore piping NDE E-67 examination. This sample population provides adequate indication of whether inside diameter cracking is occurring in small-bore piping.

The staff disagreed with the applicant's response in that socket-welded piping, 1-inch NPS and less, is adequately represented by the applicant's sample selection criteria for small bore piping included in the scope of the One-Time Inspection Program. The staff disputed that, historically, piping 1-inch NPS and less, is more susceptible to failure. The geometry of and joining methods for socket welds make them more susceptible to cracking than full penetration butt welds. But, the staff would be willing to accept NDE of full penetration butt welds in piping greater than 1-inch NPS as being representative of socket-welded piping, 1-inch NPS and less.

In RAI 3.1.2.4-7, dated March 11, 2005, the staff questioned why the applicant was not complying with the GALL Report recommendation that a plant-specific destructive examination or a nondestructive examination (NDE) that permits inspection of the inside surfaces of the piping be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the extended period.

In its response, dated April 5, 2005, the applicant stated that:

The One-Time Inspection Program will evaluate a sample of welds in small-bore piping less than 4 inches NPS for internal surface cracking by NDE as specified by NUREG-1800, Aging Management Program XI.M32, "One-Time Inspection." The BFN One-Time Inspection Program sample will be selected from full penetration butt welds where ultrasonic testing can be performed. The basis for this sample population is:

- this sample will evaluate the welds with the most susceptibility to the aging effects of stress corrosion cracking and thermal fatigue;
- this sample will evaluate the welds with the most significant consequences and risks; and
- this sample will allow the welds to be identified, scheduled, and performed in a systematic manner.

> Socket weld cracking generally occurs due to weld defect propagation by vibrational fatigue. Stress corrosion cracking and thermal fatigue rarely cause socket weld failures. Vibration induced socket weld failures is a design issue that has been observed in the nuclear power industry and can result in crack initiation and growth. Vibration induced fatigue is fast acting and is typically detected early in a component's life. Corrective measures typically include actions to preclude recurrence of the failure mechanism. Corrective actions to preclude recurrence may involve modifications to the plant, such as addition of supplemental restraints to a piping system, shortening the vent piping, replacement of tubing with flexible hose, etc. Based upon these measures, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.
>
> Previously, plants have excluded piping based strictly on consequences of the potential pipe failure. Although this was not done in the BFN Risk Informed ISI Program, a plant specific calculation demonstrates that BFN can tolerate 2-inch NPS and smaller breaks with normal makeup. At BFN, all Class 1 piping was included in the BFN Risk Informed ISI Program. No welds less than 4 inches NPS were identified as high risk. The BFN One-Time Inspection Program sample will select full penetration butt welds where ultrasonic testing can be performed. The butt welds are more susceptible to stress corrosion cracking and thermal fatigue, which are the primary crack initiation and growth aging mechanisms. This sample also allows a selection of the most risk-significant small-bore piping locations (i.e., locations with the highest susceptibility to cracking and highest consequences of failure) to be identified, scheduled, and performed in a systematic manner, rather than attempting to track modifications for 20 years while awaiting the possible removal of a piece of small-bore piping containing a weld for destructive testing.

The staff evaluated the applicant's response and concurred with the evaluation. Therefore, the staff's concern described in RAI 3.1.2.4-7 is resolved.

The staff also asked the applicant where GALL Report Volume 1, Table 1, Item 3.1.1.8, jet pump sensing line and reactor vessel flange detection line, as stated in LRA Section 3.1.2.2.4, are addressed in the AMR. By letter dated October 8, 2004, the applicant submitted its formal response to the staff. The applicant stated:

> GALL Volume 1, Table 1, Item 3.1.1.8 states that the corresponding GALL Volume 2 line items are IV.A1.1-d and IV.B1.4-d.
>
> GALL Volume 2, Line IV.A1.1-d:
>
> The Browns Ferry top head enclosure - vessel flange leak detection line is not consistent with GALL Volume 2, Line IV.A1.1-d. The Browns Ferry components included in this line item are carbon and low-alloy steel, whereas GALL Volume 2, Line IV.A1.1-d refers to stainless steel. The components included in this line item are the penetration through the carbon steel vessel flange and a short segment of carbon steel piping and fittings external to the reactor vessel. Therefore this line was not shown as corresponding to GALL Volume 1, Table 1, Item 3.1.1.8.
>
> Currently, One-Time Inspection is listed as the aging management program for this line item. The Browns Ferry reactor vessel flange leak detection line is ASME Class 2

Equivalent and should have included the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program as an aging management program. ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program will be added to this line item.

The remaining portion of the vessel flange leak detection line is stainless steel. This stainless steel piping is in the Feedwater System (003) at Browns Ferry. Aging of this piping is addressed in Table 3.4.2.3 and corresponds to GALL, Volume 2, Item C1.1-i, piping and fittings - small bore piping less than NPS 4.

GALL Volume 2, Line IV.B1.4-d:

The Browns Ferry jet pump assemblies - jet pump sensing line is not consistent with GALL Volume 2, Line IV.B1.4-d. Section IV.B1 addresses BWR reactor vessel internals. The jet pump sensing lines internal to the reactor vessel have been determined to not be within the scope of license renewal for Browns Ferry. Therefore this line was not shown as corresponding to GALL Volume 1, Table 1, Item 3.1.1.8.

The jet pump instrumentation penetration is stainless steel clad carbon steel and is included with GALL Volume 2, Line IV.A1.5-a, Penetrations. External to the reactor vessel, the stainless steel jet pump sensing lines are included in GALL, Volume 2, Item C1.1-i, piping and fittings - small bore piping less than NPS 4.

In a follow-up response to the staff's question, the applicant provided the following ARM table information:

Jet Pump

- Internal to RV – not in scope
- Penetration – Table 3.1.2.1, Items 63, 64, and 65
- External to RV – Table 3.4.2.3, Items 40 and 41

RV flange leak detection line

- Penetration – Table 3.1.2.1, Item 9
- External to RV – Table 3.1.2.4, Items 88, 89, and 90

The staff found the response acceptable on the basis that the applicant had adequately described its AMR for the jet pump and RV flange leak detection line, and also identified an appropriate correction to the AMR for the RV flange leak detection line.

During the onsite audit, the staff asked the applicant a question related to proposed AMPs for cracking of small bore piping due to cyclic loading. GALL Report Volume 1, Table 1, Item 3.1.1.7 identifies the Chemistry Control, the One-Time Inspection, and the ASME ISI Programs for managing this aging effect. However, the applicant has not included the Chemistry Control Program as one of the proposed AMPs. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating:

GALL Volume 1, Table 1 specifies that consistency with GALL Volume 2, Line IV.C1.1-i establishes consistency with GALL Volume 1, Table 1, Item 3.1.1.7. Previous to the Browns Ferry LRA, all license renewal applications have been written at the aging effect level and did not address aging mechanisms. The primary difficulty in determining GALL line item consistency is that the aging management programs should be consistent with the aging effects listed, not necessarily with the individual aging mechanisms listed. Therefore when reviewing the aging mechanism "crack initiation/growth due to cyclic loading" instead of the aging effect "crack initiation/growth," some interpretation of the GALL line item was required.

GALL Report Item IV.C1.1-i addresses specific concerns with small bore piping and fittings less than NPS 4. The GALL line item provides a comprehensive listing of potential aging mechanisms and aging management programs for the crack initiation and growth aging effect. To address that all materials and aging management programs are not applicable to each aging mechanism, this GALL line item was interpreted follows for the various materials and aging mechanisms.

<u>Stainless steel/Treated water (Note 1)</u>

Aging Effect

- Crack initiation and growth/ Stress corrosion cracking, inter-granular stress corrosion cracking

Aging Management Programs

- ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)

<u>Stainless steel/Treated water (Note 2)</u>

Aging Effect

- Crack initiation and growth/ Thermal and mechanical loading

Aging Management Programs

- ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program (B.2.1.4)
- One-Time Inspection Program (B.2.1.29)

<u>Carbon steel/Treated water (Note 3)</u>

Aging Effect

- Crack initiation and growth/ Stress corrosion cracking, inter-granular stress corrosion cracking

Aging Management Programs

- None

<u>Carbon steel/Treated water (Note 4)</u>

Aging Effect

- Crack initiation and growth/ Thermal and mechanical loading

Aging Management Programs

- ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program (B.2.1.4)
- One-Time Inspection Program (B.2.1.29)

NOTES:

1. For crack initiation and growth due to stress corrosion cracking and inter-granular stress corrosion cracking of stainless steel, the three aging management programs included in GALL line item IV.C1.1-i are applicable and are specified by the Browns Ferry LRA.
2. For crack initiation and growth due to thermal and mechanical loading of stainless steel, continued application of cyclic stresses can produce crack growth once a crack or crack-like flaw has initiated. This is a purely mechanical function and is not managed or mitigated by the Chemistry Control Program. The purpose of these examinations is to identify flaws that may lead to unstable crack growth in the pressure boundary during service. The welds in the piping and fittings are basically the same material as one or both of the parts being joined and are regarded as having higher potential for flaws than base material to experience flaw growth during plant operation. Therefore, the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program focuses on welds and a One-Time Inspection Program augments the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program for verifying that service-induced cracking is not occurring in the small-bore piping less than NPS 4.
3. For crack initiation and growth due to stress corrosion cracking and inter-granular stress corrosion cracking of carbon and low-alloy steels, no aging management programs are applicable as carbon and low-alloy steels are not susceptible to stress corrosion cracking in this application.
4. For crack initiation and growth due to thermal and mechanical loading of carbon and low-alloy steels, continued application of cyclic stresses can produce crack growth once a crack or crack-like flaw has initiated. This is a purely mechanical function and is not managed or mitigated by the Chemistry Control Program. The purpose of these examinations is to identify flaws that may lead to unstable crack growth in the pressure boundary during service. The welds in the piping and fittings are basically the same material as one or both of the parts being joined and are regarded as having higher potential for flaws than base material to experience flaw growth during plant operation. Therefore, the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program focuses on welds and a One-Time Inspection Program augments the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program for verifying that service-induced cracking is not occurring in the small-bore piping less than NPS 4.

The staff found the applicant's basis for not crediting the Chemistry Control Program to be appropriate and acceptable. The GALL Report specifies AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," to detect crack initiation and growth in components, and AMP XI.M2, "Water Chemistry," to mitigate crack initiation and growth due to SCC. The GALL Report further specifies AMP XI.M32, "One-Time Inspection," as an acceptable method to verify that cracking is not occurring in small bore piping. Since cracking due to cyclic loading is caused by mechanical or thermal loads, as opposed to an adverse chemical environment, the staff accepted the applicant's basis for not crediting the Chemistry Control Program as an AMP for managing cracking due to cyclic loading. The applicant appropriately credited the Chemistry Control Program to mitigate crack initiation and growth due to SCC.

On the basis of its review of the scope of Chemistry Control Program, One-Time Inspection Program, and the ASME ISI Program, the staff found that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to thermal and mechanical loading and SCC, consistent with the recommendations in the GALL Report.

3.1.2.2.5 Crack Growth due to Cyclic Loading

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.6 Changes in Dimension due to Void Swelling

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.7 Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.8 Crack Initiation and Growth due to Stress Corrosion Cracking or Irradiation Assisted Stress Corrosion Cracking

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.9 Loss of Preload due to Stress Relaxation

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.10 Loss of Section Thickness due to Erosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

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

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.12 Loss of Section Thickness due to Flow Accelerated Corrosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.13 Ligament Cracking due to Corrosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.14 Loss of Material due to Flow Accelerated Corrosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.1.2.2.15 Quality Assurance for Aging Management of Non-Safety-Related Components

The applicant referenced LRA Section B.1.3. The staff's evaluation of LRA Section B.1.3 is provided in SER Section 3.0.4.

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 (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant 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).

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 LRA Tables 3.1.2.1 through 3.1.2.4, the staff reviewed additional details of the results of the AMRs for material, environment, aging program (MEAP) combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.1.2.1 through 3.1.2.4, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item 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 had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

During the onsite audit, the staff reviewed selected AMR results in LRA Tables 3.1.2.1 through 3.1.2.4, for MEAP combinations that are not consistent with the GALL Report.

3.1.2.3.1 Reactor Vessel – Summary of Aging Management Evaluation – Table 3.1.2.1

The staff reviewed LRA Table 3.1.2.1, which summarizes the results of AMR evaluations for the component groups.

During the onsite audit, the reactor vessel components evaluated by the staff were the reactor vessel attachment welds, the reactor vessel closure studs and nuts, the reactor vessel support skirt and attachment welds, the refueling bellows support skirt, and the stabilizer bracket.

The staff reviewed LRA Table 3.1.2.1, which summarizes the results of the applicant's AMR evaluations for the reactor vessel pressure boundary component groups.

The onsite audit scope for the reactor vessel components did not include any MEAP combinations that are not consistent with the GALL Report.

For the carbon and low-alloy steel components (reactor vessel support skirt and attachment welds, the refueling bellows support skirt, and the stabilizer bracket), exposed externally to inside air of the containment, the applicant identified cracking due to fatigue as a TLAA. TLAAs are evaluated in SER Section 4.

3.1.2.3.2 Reactor Vessel Internals – Summary of Aging Management Evaluation – Table 3.1.2.2

The staff reviewed LRA Table 3.1.2.2, which summarizes the results of AMR evaluations for the reactor vessel internals component groups.

In LRA Table 3.1.2.2, the applicant's AMR for almost all the RVI components is consistent with the GALL Report. In addition, the applicant has identified several stainless steel and nickel-alloy RVI components (i.e., core shroud and core plate, top guide, spray lines and spargers, fuel support, CRD housing, and dry tubes and guide tubes), in a treated-water environment, as being subject to loss of material due to crevice and pitting corrosion; this is not addressed in the GALL Report. To manage this aging effect, the applicant credits the BWR Vessel Internals

Program, and Chemistry Control Program. The staff accepted the Chemistry Control Program to minimize the potential for loss of material in these components. The BWR Vessel Internals Program would detect any loss of material, if it is occurring. The BWR Vessel Internals Program includes BWRVIP recommendations for an effective inservice inspection of reactor vessel internal components.

In LRA Table 3.1.2.2, the applicant credits the BWR Vessel Internals Program and Chemistry Control Program to manage cracking in nickel-alloy components of the core spray lines and sparger assembly, and the stainless steel fuel supports. The staff found that the applicant will manage cracking in a manner consistent with the GALL Report.

In LRA Table 3.1.2.2, the applicant identified no aging effect for (1) stainless steel CRD housing external surfaces exposed to containment air and (2) stainless steel dry tube/guide tube internal surfaces exposed to air/gas. Air is not identified in the GALL Report as an environment for these components and materials. On the basis of current industry research and operating experience, an internal/external environment of gas (which is similar to dry air) on metal will not result in aging that will be of concern during the period of extended operation. Therefore, the staff concluded that there are no applicable aging effects for stainless steel in a gas environment.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.1.2.3.3 Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation – Table 3.1.2.3

The staff reviewed LRA Table 3.1.2.3, which summarizes the results of AMR evaluations for the reactor vessel internals component groups.

In LRA Table 3.1.2.3, the applicant included pressure boundary components (i.e., piping, pipe fittings, and valves) for vents and drains associated with the RCS. The GALL Report includes some of these RCS components as part of the steam and power conversion systems in GALL Report Chapter VIII. Most of these components are made of either carbon/low-alloy steel or stainless steel, and are exposed to air/gas, inside air, or treated-water environment.

The applicant identified no aging effects for stainless steel components exposed to an internal environment of air/gas for piping and fittings, or for carbon/low-alloy steel components exposed to inside air greater than 212 °F on external surfaces. Gas is not identified in the GALL Report as an environment for these components and materials. On the basis of current industry research and operating experience, the staff concluded that an internal environment of gas (which is similar to dry air) on stainless steel components will not result in aging that will be of concern during the period of extended operation, and found that the applicant’s AMR is acceptable for stainless steel exposed to a gas environment. For carbon/low-alloy steel components exposed to inside air greater than 212 °F on external surfaces, the staff found that the applicant’s AMR is acceptable, because the high environmental temperature precludes the presence of moisture on the external surfaces.

The applicant proposes to manage loss of material of carbon steel piping and valve component groups exposed to air/gas using the One-Time Inspection Program, which is a new plant-specific program. Visual inspections of the internal surfaces of plant components and plant commodities are performed during the performance of maintenance to determine loss of material. The staff found that the One-Time Inspection Program is acceptable for managing loss of material due to general corrosion since visual inspection will be performed on internal surfaces of components to detect any sign of aging degradation.

In LRA Table 3.1.2.3, the applicant identified the Flow-Accelerated Corrosion Program, to manage loss of material due to flow accelerated corrosion in piping and fittings made of carbon/low-alloy steel. This program includes analysis to determine critical locations, baseline inspections to determine the extent of thinning at these locations, and follow-up inspections to confirm the predictions. Repair, replacements, or re-evaluations are performed as necessary. The staff found that the applicant identified the appropriate AMP for this aging effect.

In LRA Table 3.1.2.3, the applicant identified that loss of material due to general, crevice, pitting and galvanic corrosion in both carbon/low-alloy steel and stainless steel piping and fittings in the reactor vessel vents and drains lines is managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In RAI 3.1.2.3-1, dated December 1, 2004, the staff stated that, in LRA Table 3.1.2.3, the applicant identified loss of bolting function (loss of material) as an applicable aging effect due to wear. The bolting is exposed externally to the inside air environment and the applicant credited its Bolting Integrity Program with management of this aging effect. Therefore, the staff requested that the applicant provide information on the scope and techniques of past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections, and any other relevant information.

In its response, by letter dated January 31, 2005, the applicant stated that bolting degradation due to wear could occur at locations of repeated relative motion of mechanical component bolted joints. Wear of bolted joint components is generally not a concern as demonstrated by industry operation experience and is not an AERM for the period of extended operation. For license renewal purposes only, wear is assumed as a potential mechanism for critical bolting applications. Critical bolting applications constitute RCPB components where closure bolting failure could result in loss of reactor coolant and jeopardize safe operation of the plant.

The staff concurred with the applicant's identification of loss of bolting function due to wear in carbon and low-alloy steel and stainless steel bolting associated with GALL Report Items IV.C1.3-e and IV.C1.2-d. For those components that fall under the GALL Report Item IV.C1.2-d, the applicant indicated that the material listed in the GALL Report is different from the material used at BFN (LRA Table 3.1.2.4, Footnote F). The applicant stated that the bolting used for recirculation pump closure bolting is ASTM A540 Grade B23. Although the GALL Report lists high-strength low-alloy (HSLA) steel SA-193 Grade B7 for the applicable component, the staff concludes that degradation due to wear of ASTM A540 Grade B23 bolting will be adequately managed by the applicant's Bolting Integrity Program and is acceptable. Therefore, the staff's concern described in RAI 3.1.2.3-1 is resolved.

The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

3.1.2.3.4 Reactor Vessel Recirculation System – Summary of Aging Management Evaluation – Table 3.1.2.4

The staff reviewed LRA Table 3.1.2.4 and Section 3.1.2.1.4. which summarize the results of AMR evaluations for the reactor recirculation system component groups. The component groups for this system include piping and fittings (including flexible connections, flow restricting orifices and strainers), valves, pumps, tanks, and heat exchangers. The bolting group in this system is not part of the onsite audit scope.

In LRA Table 3.1.2.4, the applicant identified no aging effects in reactor recirculation component groups, for stainless steel and copper alloy carrying air/gas; for carbon/low-alloy steel, glass (fittings), and stainless steel, with external surface exposed to inside air; and for cast iron/cast-iron alloys, carbon/low-alloy steel, copper alloys, glass (fittings), and stainless steel carrying lubricating oil. Air and lubricating oil are not identified in the GALL Report as environments for these components and materials. Those components carrying lubricating oil are not subject to wetting and their surfaces always remain oil-coated because they are continuously in service.

During the onsite audit, the staff asked the applicant if there exists any contamination of water in the components that carry lubricating oil. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that:

> Lubricating oil systems generally do not suffer appreciable degradation by cracking or loss of material since the environment is not conducive to corrosion mechanisms. In addressing the question, "Is there a potential for water contamination?" plant experience (i.e., maintenance/ operating history) is utilized as a basis for conclusions reached. The lubricating oil applications where there is no history of water contamination do not have any potential aging mechanisms. Those applications where water contamination does occur, such as the diesel generator combustion air intake filters, potential loss of material due to general, pitting, and crevice corrosion was identified as requiring management for the period of extended operation.

Based on the applicant's response, the staff concluded that the applicant had appropriately addressed the lubricating oil environment in its AMR. Those components that are susceptible to such contamination are identified, and aging management for loss of material is specified.

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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion of low-alloy steel requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components will experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Wrought austenitic stainless steels are not susceptible to significant general corrosion that would affect the intended function of components. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In components made from cast iron, copper alloy, copper-zinc alloys, brass, ductile iron, and bronze, selective leaching takes place when these components are exposed to raw water, corrosion-inhibited treated water, oxygenated and de-oxygenated treated water, or are buried underground. In LRA Table 3.1.2.4, the applicant identified the Selective Leaching of Materials Program to manage loss of material due to selective leaching in copper-alloy components associated with heat exchangers and tubing, valves, and pipe fittings exposed to raw water and treated water. The applicant's selective leaching program relies on visual inspections and hardness measurements of selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Cast iron/cast-iron alloy fittings exposed to air/gas, carbon/low-alloy steel piping/fittings and valves exposed to air/gas, and stainless steel components of heat exchangers exposed to raw water (potable) or treated water are susceptible to loss of material due to pitting, crevice and general corrosion, biofouling, and MIC. In LRA Table 3.1.2.4 (rows 60, 63, 65, and 66), the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities.

During the onsite audit, the staff noted corrosion, biofouling, and MIC in stainless steel and copper components in heat exchangers exposed to raw water or treated water that are managed by One-Time Inspection Program. The staff asked if there were any other AMPs that periodically inspect heat exchangers subject to these aging mechanisms. By letter dated October 8, 2004, the applicant submitted its formal response to the staff as follows:

> For Table 3.1.2.4, Reactor Recirculation System, the raw water is supplied from the Raw Cooling Water System and should specify the Open-Cycle Cooling Water Program as the appropriate aging management program.
>
> For Table 3.1.2.4, Reactor Recirculation System, the treated water refers to a self-contained cooling water system supplied with the Variable Frequency Drives. The Chemistry Control Program and the One-Time Inspection Program are the appropriate aging management programs for this cooling water system.

The staff concurred that the Open-Cycle Cooling Water Program for heat exchangers exposed to raw water and the Chemistry Control Program/One-Time Inspection Program for heat exchangers exposed to treated water are the appropriate AMPs. These programs are able to manage the aging effects due to corrosion, biofouling, and MIC in these components.

Cast iron/cast iron-alloy component external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

In LRA Table 3.1.2.4, heat exchanger components made of carbon/low-alloy steel and exposed to raw water are susceptible to loss of material due to biofouling, MIC, crevice, galvanic, general, and pitting corrosion. The applicant credited the Open-Cycle Cooling Water System Program to manage these aging effects. These AMP activities, in accordance with the guidelines of GL 89-13, include managing aging effects by condition monitoring (system and component testing, visual inspections, and NDE testing), and by preventive actions (biocide treatment and filtering to prevent loss of material due to MIC, biofouling, flow blockage and reduction of heat transfer due to biological and particulate fouling). The staff found this acceptable.

In LRA Table 3.1.2.4, the applicant identified that the loss of material due to general, crevice, pitting, and galvanic corrosion in both carbon/low-alloy steel and stainless steel piping and fittings and crack initiation/growth due to SCC in stainless steel piping and fittings in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component’s intended function will be maintained during the period of extended operation.

In LRA Table 3.1.2.4, the applicant identified loss of bolting function due to wear as an AERM for carbon, low-alloy, and stainless steel components that are exposed externally to the inside air environment. The applicant's AMR for these components has categorized them as one of the following: 1) Material not in the GALL Report item for this component (i.e., LRA Table 3.1.2.4, Footnote F), or 2) Consistent with the GALL Report item for component, material, environment, and aging effect. The AMP takes some exception to GALL (i.e., LRA Table 3.1.2.4, Footnote B). The applicable bolting is the RCPB valve closure bolting (GALL Report Item IV.C1.3-e) and reactor recirculation pump closure bolting (GALL Report Item IV.C1.2-d). The applicant credits the Bolting Integrity Program in LRA Section B.2.1.16 with the management of loss of bolting function due to wear of the aforementioned carbon and low-alloy steel and stainless steel bolts.

In RAI 3.1.2.3-1(C), dated December 16, 2004, the staff stated that the LRA identified loss of bolting function (loss of material) as an applicable aging effect due to wear. The bolting is exposed externally to the inside air environment and the applicant credited its Bolting Integrity Program with management of this aging effect. Therefore, the staff requested that the applicant provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the Bolting Integrity Program. In response to RAI 3.1.2.3-1(C), by letter dated January 31, 2005, the applicant provided the following summary of its aging effect evaluation for wear.

> Bolting degradation due to wear could potentially occur at locations of repeated relative motion of mechanical component bolted joints. Wear of bolted joint components is generally not a concern; however, for license renewal purposes, wear is being assumed as a potential mechanism for 'critical bolting applications.' 'Critical bolting applications' constitute reactor coolant pressure boundary components where closure bolting failure could result in loss of reactor coolant and jeopardize safe operation of the plant. These locations include bolted joints on the recirculation pumps and reactor coolant pressure boundary valves. Therefore, wear of reactor coolant pressure boundary bolted joints requires aging management for the period of extended operation.

The staff concurred with the applicant's identification of loss of bolting function due to wear, in carbon and low-alloy steel and stainless steel bolting associated with GALL Report Items IV.C1.3-e and IV.C1.2-d.

In LRA Table 3.1.2.4, for those components that fall under GALL Report Item IV.C1.2-d, the applicant indicated that the material listed in the GALL Report is different from the material used at BFN (LRA Table 3.1.2.4, Footnote F). The applicant stated that the bolting used for recirculation pump closure bolting is ASTM A540 Grade B23. Although the GALL Report lists HSLA steel SA-193 Grade B7 for the applicable component, the staff concludes that degradation due to wear of ASTM A540 Grade B23 bolting will be adequately managed by the applicant's Bolting Integrity Program and is, therefore, acceptable.

In LRA Table 3.1.2.4, for those components that fall under GALL Report Item IV.C1.3-e, RCPB valve closure bolting, the applicant stated that the bolting is consistent with the GALL Report item for component, material, environment, and aging effect in which the applicant's AMP takes some exception to GALL Report Volume 2, (LRA Table 3.1.2.4, Footnote B). The staff found acceptable the applicant's use of the Bolting Integrity Program, with exceptions, to manage wear of GALL Report Item IV.C1.3-e components.

In LRA Table 3.1.2.4, the applicant identified loss of preload as an applicable aging effect due to stress relaxation. The bolting is exposed externally to the inside air environment and the applicant credited its Bolting Integrity Program with management of this aging effect. The staff concurs with the applicant that carbon and low-alloy steel and stainless steel bolting identified above are susceptible to loss of preload due to stress relaxation when exposed externally to the inside air environment. For those components that the applicant lists as being fabricated from a material not listed for corresponding GALL Report, Volume 2, Item IV.C1.2-e, the applicant indicates that ASTM A 540 Grade B23 bolting is used in lieu of ASME SA 193 Grade B7, which is listed in GALL Report Item IV.C1.2-e.

In RAI-3.1.2.4-1(A), dated December 1, 2004, the staff requested the applicant to provide additional information on the previous plant-specific experience of loss of bolting function due to this aging effect. In addition, the applicant was asked to provide information on the scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, frequency of its inspections and any other relevant information related to the identification of this aging effect of the reactor recirculation systems and to provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the Bolting Integrity Program.

In its response, by letter dated January 31, 2005 the applicant stated:

> Stress relaxation was identified to be an aging effect that requires management for the period of extended operation for the reactor water recirculation pump closure bolting in LRA Table 3.1.2.4, line item 2. The reactor water recirculation pump closure bolting is inspected in accordance with the requirements of ASME Section XI, Table IWB-2500-1, Category B-G-1. Results of these inspections are provided below. [Table of Results is listed in RAI response]

Based on this review, no repairs have been performed on the reactor recirculation pump closure bolting. As discussed in LRA Section B.2.1.16, EPRI NP-5769, and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of SR bolting have been implemented. The plant-specific experience related to reactor recirculation pump closure bolting has no impact on the attributes specified in the Bolting Integrity Program.

The staff found the applicant's response to RAI 3.1.2.4-1(A) acceptable and concluded that the applicant's use of the Bolting Integrity Program will adequately manage loss of preload due to stress relaxation in recirculation pump closure bolting, GALL Report Item IV.C1.2-e. Therefore, the staff's concern described in RAI 3.1.2.4-1(A) is resolved.

In LRA Table 3.1.2.4, the applicant lists RCPB valve closure bolting, (GALL Report Item IV.C1.3-f), as being susceptible to loss of bolting function due to stress relaxation. Revised LRA Table 3.1.2.4 indicates that ASME SA 193 Grade B7 is used in some applications and the Bolting Integrity Program is credited with managing this aging effect. The component, material, environment, and aging effect are consistent with the GALL Report. The AMP takes some exceptions to the GALL Report. The staff found this acceptable.

The applicant also lists ASTM A 540 Grade B23 as being used for RCPB valve closure bolting (GALL Report Item IV.C1.3-f). Although the material is different from that listed in the GALL Report, it is very similar and would be susceptible to the same aging effects as ASME SA 193 Grade B7. It would also be adequately managed by the same AMP (Bolting Integrity Program). Therefore, the staff finds the applicant's use of the Bolting Integrity Program as an acceptable method to manage loss of preload as a result of stress relaxation during the period of extended operation.

In LRA Table 3.1.2.4, the applicant identified loss of bolting function (cumulative fatigue damage) due to fatigue as an applicable aging effects for carbon and low-alloy steel bolting used on the recirculation pump and RCPB valve closure bolting. The applicant indicated that ASTM A 540 Grade B23 as well as ASME SA 193 Grade B-7 are used. ASME SA 193 Grade B-7 is the material referenced in the GALL Report for these components. These two materials are similar and would both be potentially susceptible to fatigue. Therefore, the staff concurred with the applicant that the referenced components are subject to cumulative fatigue damage when exposed to inside air (external) environments.

For the reactor recirculation pump closure bolting (GALL Report Item IV.C1.2-f), the applicant listed fatigue as an applicable aging effect and indicated that fatigue is evaluated as a TLAA and referenced LRA Section 4.3. The applicant indicated that its TLAA is consistent with the GALL Report. The staff found the applicant's use of the TLAA "Metal Fatigue" in LRA Section 4.3, acceptable to manage loss of bolting function due to fatigue for the period of extended operation.

The applicant lists ASTM A 540 Grade B23 and ASME SA 193 Grade B7 as bolts used in the RCPB as valve closure bolting (GALL Report Item IV.C1.3-g). The material listed in the GALL Report for this item number is SA 193 Grade B7. GALL requires a TLAA, meeting the requirements of 10 CFR 54.21(c), to be performed for the extended period of operation for GALL Report Item IV.C1.3-g. ASTM A 540 Grade B23 is also potentially susceptible to fatigue and the staff considers the GALL Report requirements for ASME SA 193 Grade B7 to also be applicable to ASTM A540 Grade B23 bolting with regard to fatigue. The applicant indicated that it has performed a TLAA that meets the requirements of 10 CFR 54.21(c) for ASTM A 540 Grade B23 and ASME SA 193 Grade B7 bolting used for RCPB valve closure bolting identified as GALL Report Item IV.C1.3-g. Therefore, the staff found the applicant's AMR for these items acceptable.

In LRA Table 3.1.2.4, the applicant identified biofouling and loss of material due to MIC, and crevice and pitting corrosion as AERMs in copper-alloy heat exchanger components that are exposed to raw water environments internally. The AMR for these components has categorized them as the following: neither the component nor the material and environment combination is evaluated in the GALL Report (i.e., LRA Table 3.1.2.4, Footnote J). The applicant credits the Open-Cycle Cooling Water System Program to manage aging effects caused by biofouling and applicable forms of corrosion. The Open-Cycle Cooling Water System Program is evaluated in LRA Section 3.0.3.1.

The applicant identified loss of material due to crevice and pitting corrosion in copper-alloy piping in a treated water (internal) environment, GALL Report Item VII.C2.1-a. The applicant indicated in the LRA that the One-Time Inspection Program is the credited AMP. The applicant indicated that the material used is not consistent with the GALL Report and that the aging effects identified for this material/environment combination are consistent with industry guidance.

The staff concurred with the applicant’s determination that copper-alloy heat exchanger components that are subjected to a raw water environment internally are susceptible to biofouling and loss of material due to MIC, crevice and pitting corrosion. The staff also concurred with the applicant’s identification of crevice and pitting corrosion in copper-alloy piping in a treated-water environment.

In RAI 3.1.2.4-3, dated November 4, 2004, the staff requested the applicant to provide information regarding the heat exchangers, their function, and the selection of the credited AMP (One-Time Inspection Program). In its response, by letter dated December 9, 2004, the applicant stated that the heat exchangers identified in LRA Table 3.1.2.4, Reactor Recirculation System, are the reactor recirculation pump motor generator raw water/lubrication oil heat exchangers for Unit 1 and the reactor recirculation pump, variable frequency drive, raw water heat exchangers for Units 2 and 3. The Unit 1 reactor recirculation pump motor generators will be replaced by variable frequency drives prior to Unit 1 restart. The applicant also stated that the raw water environment for the heat exchangers is supplied from the raw water cooling system and the appropriate AMP is the Open-Cycle Cooling Water Program. The Open-Cycle

Cooling Water System Program includes condition monitoring such as system and component testing, visual inspection, and NDE testing. Preventive actions such as biocide treatment and filtering are used to prevent loss of material due to MIC, biofouling, flow blockage, and reduction of heat transfer due to biological and particle fouling. The applicant's Open-Cycle Cooling Water System Program is evaluated in SER Section 3.0.3.1 and consistent with the GALL Report after enhancements. The AMP credited by the applicant provides reasonable assurance that the aging effects caused by biofouling, MIC, and crevice and pitting corrosion will be adequately managed. The staff's concern described in RAI 3.1.2.4-3 is resolved.

For copper piping in a treated-water environment (internal), which the applicant identified as being susceptible to loss of material due to crevice and pitting corrosion, the staff requested in RAI 3.1.2.4-4, dated November 4, 2004, that the applicant provide more information regarding the operating and inspection history of the components. In its response, by letter dated December 9, 2004, the applicant stated that the copper-alloy piping is an integral part of the reactor recirculation pump variable frequency drives, which are recent additions to Unit 2 in 2003 and Unit 3 in 2004. Reactor recirculation pump variable speed drives will be installed in Unit 1 prior to start up. The vendor manual identifies the material as red brass. The applicant stated that the appropriate AMP is the Chemistry Control Program and the One-Time Inspection Program. Red brass could suffer loss of material in a treated-water environment if the chemistry is not controlled properly. Given that the applicant will perform a one-time inspection to ensure that degradation has not occurred and control the chemistry of the treated water, the potential degradation of this piping due to crevice and pitting corrosion will be adequately managed during the extended period of operation.

The staff reviewed the applicant's AMR for evaluating biofouling and loss of material due to MIC, crevice and pitting corrosion in heat exchanger copper-alloy components listed in LRA Table 3.1.2.4 that are exposed to a raw water (internal) environment. The staff also reviewed the applicant's AMR for evaluating loss of material due to crevice and pitting corrosion in copper-alloy piping (GALL Report Item VII.C2.1-a) in a treated-water environment. On the basis of its review, the staff found that the applicant had demonstrated that the effects of aging for these components will be adequately managed 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).

3.1.2.3.5 Components with No Aging Effects in Inside Air Environment Externally and Components with No Aging Effects in Treated Water Environment Internally

In LRA Table 3.1.2.4, the applicant identified several components where the materials used are not susceptible to aging effects identified in the GALL Report. The AMRs for these components have categorized them as the following: material is not in the GALL Report item for this component (i.e., LRA Table 3.1.2.4, Footnote F) and aging effect in the GALL Report item for this component, material/environment combination is not applicable (i.e., LRA Table 3.1.2.4, Footnote I). In evaluating the aging effect, the applicant stated that for GALL Report Items V.E.2-b and VII.I.2-b, carbon and low-alloy steel bolting are identified as being susceptible to crack initiation and growth due to cyclic loading and SCC. GALL specifies the use of a Bolting Integrity Program in accordance with GALL AMP XI.M18. Under plant-specific notes, LRA Table 3.1.2.4, Footnote 3, the applicant indicated that high yield-strength, heat-treated bolting is not used and SCC and cracking due to cyclic loading are not concerns for BFN license renewal.

The applicant provided additional information along with its revised LRA Table 3.1.2.4 by letter dated March 16, 2005. The applicant stated the following:

> The aging management review determined that this bolting is not susceptible to SCC as the yield strength of the ASME SA 193 Grade B7 bolting is less than 150 ksi. Crack initiation and growth due to cyclic loading is not considered a license renewal concern due to high cycle fatigue since it would be discovered during the current license period and corrected. In addition, cyclic primary loads are evaluated against conservative stress limits and are not a contributor to fatigue due to the few number of stress cycles postulated (e.g., earthquake and fluid transient loads). The absence of crack growth due to cyclic loading and stress corrosion cracking identified in current line items 6 and 8 is now shown in line items 10 and 12.

Typically, ASME SA193 Grade B7 bolting less than 150 ksi yield strength is not susceptible to SCC and would not require an AMP to manage cracking due to stress corrosion. With regard to cracking due to cyclic loading, the staff concurred with the applicant that cracking due to cyclic loading would not be applicable. The staff found the applicant's conclusion, that no AMP is required for these item numbers, acceptable.

The applicant indicated, by letter dated March 16, 2005, that stainless steel non-RCPB bolting in the reactor recirculation system boundary was evaluated for aging effects such as corrosion, cracking due to cyclic loading, SCC, wear, stress relaxation, and fatigue. These bolting/material/environment combinations are not addressed in the GALL Report. The applicant stated that the bolting in question has a yield strength less than 150 ksi. The applicant identified fatigue as being the only applicable aging effect for these bolts in an inside air (external) environment. The applicant further stated that fatigue is addressed as a TLAA in LRA Section 4.3. Based on a review of the applicant's March 16, 2005 letter, and considering the environment, material and application, the staff concurred with the applicant's conclusion and found its evaluation of the aforementioned bolts, in an inside air (external) environment, acceptable.

In GALL Report Volume 2, Items V-E-2-b and VII.I.2-b list carbon or low-alloy steel bolting as the applicable material and indicate that crack initiation and growth due to cyclic loading and SCC are aging effects that require management during the extended period of operation. Revised LRA Table 3.1.2.4 lists ASME SA 193 Grade B7, which is an HSLA material for these GALL Report item numbers. The AMR categorizes these line items as aging effects in the GALL Report item for this component/material/environment combination that are not applicable, and high yield-strength, heat-treated bolting, greater than150 ksi, is not used in non-RCPB bolting applications at BFN (as evidenced in LRA Table 3.1.2.4, Footnote I,3). The staff did not consider ASME SA 193 Grade B7 bolting less than 150 KSI as being susceptible to SCC in an inside air (external) environment as described in the applicant's LRA. Therefore, the staff concurs with the applicant's conclusion that no AMP is required for these components due to cracking as a result of cyclic or SCC in an inside air (external) environment.

GALL Report Items VII.I.1-b and V.E.1-b are listed as being carbon or low-alloy components that are susceptible to loss of material due to general corrosion in an inside air (external) environment. LRA Table 3.1.2.4 lists copper alloy as the material used and does not list any aging effects for material/environment as being applicable. The AMR categorizes this line item as “material is not in the GALL Report item for this component” (LRA Table 3.1.2.4, Footnote F). The staff does not consider copper-alloy components to be susceptible to any aging effects in an inside air (external) environment. Therefore, the staff concurred with the applicant's conclusion that no AMP is required for these components.

In RAI 3.1.2.4-5, dated November 4, 2004, the staff stated that the GALL Report Item V.C.1-b is listed as stainless steel valves; the material that is the same as used at BFN. The aging effects listed in the GALL Report as requiring management are loss of material due to pitting, crevice corrosion, MIC, and biofouling. The components are in a treated water (internal) environment, which is the same as listed in the GALL Report. Therefore, the staff requested that the applicant discuss the age, operating history, and inspection history of the valves. The staff also requested that the applicant provide a detailed explanation of the attributes of the system design that make degradation due to MIC and biofouling not applicable.

In its response, by letter dated December 9, 2004, the applicant stated that the water in this cooling water subsystem is demineralized water that has no history of microbiologically influenced corrosion activity. The staff found this acceptable because stainless steel in a demineralized water environment would not be considered susceptible to loss of material due to pitting, crevice corrosion, MIC, and biofouling. Therefore, the staff's concern described in RAI 3.1.2.4-5 is resolved.

In LRA Table 3.1.2.4, the applicant also identified several components in which the material used is not susceptible to aging effects identified in the GALL Report. The AMR for these components categorized them as the following: "material is not in GALL Report item for this component" (LRA Table 3.1.2.4, Footnote F) and the aging effect in the GALL Report item for this component/material/environmental combination is not applicable (i.e., LRA Table 3.1.2.4, Footnote I).

GALL Report Items V.E.2-b and VII.I.2-b, carbon and low-alloy steel bolting, are identified as being susceptible to crack initiation and growth due to cyclic loading and SCC. The GALL Report specifies the use of a Bolting Integrity Program in accordance with GALL Report Volume 2, Chapter XI.M18. Under plant-specific notes, LRA Table 3.1.2.4, Footnote 3, the applicant indicated that high yield-strength, heat-treated bolting is not used at BFN and SCC and cracking due to cyclic loading are not concerns for license renewal. The staff followed up and sought clarifications on the LRA Table 3.1.2.4 information.

The applicant provided additional information along with its revised LRA Table 3.1.2.4 by letter dated March 16, 2005. The applicant stated the following:

> The aging management review determined that this bolting is not susceptible to SCC as the yield strength of the ASME SA 193 Grade B7 bolting is less than 150 ksi. Crack initiation and growth due to cyclic loading is not considered a license renewal concern due to high cycle fatigue since it would be discovered during the current license period and corrected. In addition, cyclic primary loads are evaluated against conservative stress limits and are not a contributor to fatigue due to the few number of stress cycles postulated (e.g., earthquake and fluid transient loads). The absence of crack growth due to cyclic loading and stress corrosion cracking identified in current line items 6 and 8 is now shown in line items 10 and 12.

Typically, ASME SA193 Grade B7 bolting, less than 150 ksi yield strength, is not susceptible to stress corrosion cracking and would not require an AMP to manage cracking due to stress corrosion. With regard to cracking due to cyclic loading, the staff concurs with the applicant that cracking due to cyclic loading would not be applicable. The staff finds the applicant's conclusion, that no AMP is required for these item numbers, acceptable.

The applicant indicated, by letter dated March 16, 2005, that stainless steel non-RCPB bolting in the reactor recirculation system boundary was evaluated for aging effects such as corrosion, cracking due to cyclic loading and SCC, wear, stress relaxation, and fatigue. These bolting/material/environment combinations are not addressed in the GALL Report. The applicant stated that the bolting in question has a yield strength less than 150 ksi. The applicant identified fatigue as being the only applicable aging effect for these bolts in an inside air (external) environment. The applicant further stated that fatigue is addressed as a TLAA in LRA Section 4.3. Based on a review of the applicant's March 16, 2005 letter, and considering the environment, material and application, the staff concurred with the applicant's conclusion and finds its evaluation of the aforementioned bolts, in an inside air (external) environment, acceptable.

In GALL Report Volume 2, Items V-E-2-b and VII.I.2-b list carbon or low-alloy steel bolting as the applicable material and indicates that crack initiation and growth due to cyclic loading/SCC are aging effects that require management during the extended period of operation. Revised LRA Table 3.1.2.4 lists ASME SA 193 Grade B7, which is an HSLA material for these GALL Report item numbers. The AMR categorizes these line items as: “Aging effect in NUREG-1801 item for this component, material and environment combination is not applicable and high yield strength heat-treated bolting, greater than150 ksi, is not used in non-RCPB bolting applications at BFN” (LRA Table 3.1.2.4, Footnote I,3). The staff did not consider ASME SA 193 Grade B7 bolting less than 150 KSI as being susceptible to SCC in an inside air (external) environment as described in the applicant's LRA. Therefore, the staff concurred with the applicant's conclusion that no AMP is required for these components due to cracking as a result of cyclic or SCC in an inside air (external) environment.

GALL Report, Items VII.I.1-b and V.E.1-b are listed as being carbon or low-alloy components that are susceptible to loss of material due to general corrosion in an inside air (external) environment. LRA Table 3.1.2.4 lists copper alloy as the material used and does not list any aging effects for the material/environment as being applicable. The AMR categorizes this line item as “material is not in the GALL Report item for this component,” (LRA Table 3.1.2.4, Footnote F). The staff does not consider copper-alloy components to be susceptible to any aging effects in an inside air (external) environment. Therefore, the staff concurred with the applicant's conclusion that no AMP is required for these components.

3.1.2.3.6 SCC in RV Flange Leak Detection Line and Jet Pump Sensing Line

SRP-LRA Section 3.1.3.2.4.2 states that the crack initiation and growth due to thermal and mechanical loading or SCC, including IGSCC, could occur in the BWR RV flange detection line and jet pump sensing line. The GALL Report recommends that a plant-specific AMP be evaluated to mitigate or detect crack initiation and growth due to SCC of the vessel flange detection line and jet pump sensing line.

In LRA Section 3.1.2.2.4, the applicant addressed vessel flange leak detection lines that are subjected to SCC. The applicant proposed to use the One-Time Inspection Program for managing this aging effect.

In RAI 3.1.1-1, dated December 1, 2004, the staff requested that the applicant provide information on the plant-specific experience related to cracking due to SCC in the vessel flange leak detection lines at the BFN units, and its method of implementation of the One-Time Inspection Program. The staff also requested the applicant to provide justification for using one-time inspection in detecting the cracking due to SCC in a timely manner.

In its response, by letter dated January 31, 2005, the applicant indicated that, in addition to the One-Time Inspection program, the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program will be implemented for the RV flange leak detection lines. The applicant stated that it will revise the first paragraph in LRA Section 3.1.2.2.4 to include the ISI program as an additional AMP for the RV flange leak detection lines. The applicant stated that the AMR shown in LRA Table 3.1.2.1 will be revised to include the aging effects (cracking growth from cyclic loading, loss of material due to crevice, pitting, and general corrosion), and their associated AMPs (One-Time Inspection Program and ISI Program) for the carbon steel and low-alloy steel RV heads, flanges, and shells. The staff found this response acceptable. The proposed AMPs will provide adequate measures in managing the aging effects of the RV flange leak detection lines. Therefore, the staff's concern described in RAI 3.1.1-1 is resolved.

In LRA Section 3.1.2.2.4, the applicant addressed jet pump sensing lines that are subject to SCC. The applicant proposed to use the Chemistry Control Program and One-Time Inspection Program for managing this aging effect.

In RAI 3.1.1-2, dated December 1, 2004, the staff requested that the applicant provide information on the plant-specific experience related to cracking due to SCC in jet pump sensing lines, and its method of implementing the One-Time Inspection Program. The staff also requested that the applicant provide justification for using the One-Time Inspection Program to detect cracking due to SCC in a timely manner.

In its response to RAI 3.1.1-2, by letter dated January 31, 2005, the applicant stated that the jet pump sensing lines have not previously experienced cracking due to SCC, IGSCC or cyclic loading. The jet pump sensing lines inside the RV are not within the scope of the license renewal process. According to Section 2.3.12.7 of the BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," inspection of the jet pump sensing lines is continuously occurring during the plant operation. Therefore, if this line fails, plant technical specifications require either a plant shutdown or a safety assessment to justify continued operation. Therefore, the failure of the sensing lines inside the RV has no adverse safety consequences and does not need to be included within the scope of license renewal. However, the applicant agreed to revise the AMR by adding the AMPs (shown below) for the jet pump sensing line penetrations and external lines that are listed in LRA Tables 3.1.2.1 and 3.1.2.4. The applicant included the BWR Reactor Penetration Program for managing the aging effect related to cracking due to SCC in the jet pump sensing lines penetrations at BFN. The applicant stated that this AMP is consistent with GALL AMP XI.M8, "BWR Penetrations," with no exceptions. BWR Reactor Penetration Program includes the staff's approved versions of BWRVIP-27, "BWR Standby Liquid Control System/Core Plate delta P Inspection and Flaw

Evaluation Guidelines," and BWRVIP-49, "Instrumentation Penetration Inspection and Flaw Evaluation Guidelines." SER Section 3.0.3.2.6 presents the staff's detailed review of this AMP.

The staff finds the applicant's response to RAI 3.1.1-2 acceptable, and the staff's concern described in this RAI is resolved.

The applicant stated that the Chemistry Control Program will be used at BFN to manage SCC in the jet pump sensing lines. The Chemistry Control Program is based on EPRI Report TR-103515-R2, (the 2000 revision of "BWR Water Chemistry Guidelines"), which was approved by the staff in February 2000. The staff found the EPRI TR-103515-R2 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience that confirms the effectiveness of the RCS chemistry program. The staff found that implementation of the Chemistry Control Program would be consistent with the GALL AMP XI.M2; therefore, it is acceptable. In addition, the proposed inspection AMPs would ensure the identification of cracking due to SCC, IGSCC, and cyclic loading in a timely manner so that the intended function of the jet pump sensing lines is not sacrificed. Therefore, the staff concluded that by the implementation of the additional AMPs, the aforementioned aging effects of the jet pump sensing lines would be managed effectively during the extended period of operation.

3.1.2.3.7 Stainless Steel Reactor Vessel Attachment Welds

The AMPs recommended by the GALL Report for managing the cracking due to SCC, IGSCC, and cyclic loading for the RV attachment welds are XI.M4, "BWR Vessel Inner Diameter (ID) Attachment Welds," and XI.M2, "Water Chemistry," which references EPRI Report TR-103515.

In LRA Table 3.1.2.1, the applicant identified IGSCC as an aging effect for the stainless steel RV attachment welds. The applicant stated the Chemistry Control Program will be used at BFN to manage this aging effect. The Chemistry Control Program is based on EPRI Report TR-103515-R2, (the 2000 revision of "BWR Water Chemistry Guidelines"), which was approved by the staff in February 2000. The staff found EPRI TR-103515-R2 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience that confirms the effectiveness of the RCS chemistry program. The applicant indicated that the vessel attachment welds program is discussed in LRA Section B.2.1.7, "BWR Vessel ID Attachment Welds." LRA Section B.2.1.7 references LRA Section B.2.1.4, "ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program." The applicant's ISI Program is an established AMP. This program has appropriate requirements for inspecting the vessel ID attachment welds. "BWR Vessel ID Attachment Welds" also invokes the inspection and evaluation recommendations of BWRVIP-48, "Vessel ID Attachment Weld Inspection and Evaluation Guidelines." SER Section 3.0.3.2.3 presents the staff's detailed review of this AMP.

In RAI 3.1.2.1-1, dated December 1, 2004, the staff requested that the applicant provide the method of implementation of the type and frequency of inspections that are specified in BWRVIP-48, "Vessel ID Attachment Welds Inspection and Flaw Evaluation Guidelines." These requirements apply to jet pump raiser brace attachments, core spray piping bracket attachments, steam dryer support and hold-down brackets, feedwater spargers, guide rods, and surveillance sample holders. According to BWRVIP-48 Section 2.2.3, furnace-sensitized stainless steel vessel ID attachment welds are highly susceptible to IGSCC. The staff requested the applicant to identify whether there are any furnace-sensitized stainless steel attachment welds at BFN, and to provide information regarding an augmented inspection program for any existing furnace-sensitized stainless steel attachment welds.

In its response to RAI 3.1.2.1-1, by letter dated January 31, 2005, the applicant stated that all the ID RV attachment welds had been inspected in accordance with BWRVIP-48 and ASME Code Section XI ISI requirements for type and frequency. The applicant indicated that all the ID attachment welds are furnace-sensitized; therefore, an augmented inspection program in accordance with the requirements of BWRVIP-48 will be implemented for all these welds. The staff found that this type of inspection would ensure that the aforementioned aging effects are properly managed for the extended period of operation. The staff found that the implementation of the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, Chemistry Control Program, and BWR ID Attachment Welds Program would be consistent with the GALL AMPs XI.M2 and XI.M4, and is acceptable. Therefore, the staff's concern described in RAI 3.1.2.1-1 is resolved. SER Sections 3.0.3.2.2 and 3.0.3.1.3 respectively, present the staff's detailed review of these AMPs. SER Sections 3.0.3.2.2 and 3.0.3.1.3, respectively, present the staff's detailed reviews of these AMPs.

3.1.2.3.8 Reactor Vessel Nozzles and Safe Ends

The AMPs recommended by the GALL Report for managing the cracking due to SCC, IGSCC and cyclic loading for the RV nozzles and safe ends are XI.M7, "BWR Stress Corrosion Cracking," and XI.M2, "Water Chemistry," which references EPRI Report TR-103515.

In Table 3.1.2.1 of the LRA, the applicant indicated that stainless steel materials in the RV nozzle and safe end components, when exposed to a treated-water environment, experience cracking due to SCC. The applicant credited the BWR Stress Corrosion Cracking Program, ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, which is an established AMP. In addition, the applicant indicated that AMP B.2.1.5, "Chemistry Control Program," is based on EPRI Report TR-103515-R2, (the 2000 revision of "BWR Water Chemistry Guidelines"), which was approved by the staff in February 2000.

In RAI 3.1.2.1-4(C), the staff requested that the applicant identify whether the dissimilar metal welds of reactor vessel nozzles and safe end components have previously experienced cracking due to SCC, IGSCC, or cyclic loading, and the extent of cracking. In its response to RAI 3.1.2.1-4(C), by letter dated January 31, 2005, the applicant stated that, for the dissimilar metal welds in nozzles and safe end components and piping, the requirements of ASME Code Section XI, Subsections IWB, IWC and IWD ISI Program inspections and frequencies in accordance with ASME Code Section XI, Table IWB-2500-1, examination category B-F would be met. The applicant's BWR IGSCC program inspections and frequencies are in accordance with the normal water chemistry guidelines contained in BWRVIP-75, "BWR Vessel and Internals Project (BWRVIP), Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule." The applicant implemented alternative examination requirements for IGSCC Category A (as defined in BWRVIP-75) dissimilar metal welds under a risk-informed ISI program (previously approved by the staff) for Units 2 and 3. The applicant stated that it performed liquid penetrant testing (PT) and UT of the dissimilar welds in recirculation inlet and outlet nozzle-to-safe ends, the core spray nozzle-to-safe end, pipe-to-safe ends, and the CRD nozzle-to-cap welds for Units 2 and 3; and the examination results were acceptable. The applicant stated that for Unit 1 it performed PT and UT examinations on CRD nozzle-to-cap welds, and the examination results were acceptable. The applicant stated that for Unit 1 the RCS water chemistry would be improved in accordance with the BWR SCC Program, and the CRD nozzle-to-safe end welds would be replaced prior to the period of extended operation.

The applicant also stated that improvements in RCS water chemistry provide mitigative measures to preclude IGSCC in the dissimilar welds in nozzle-to-safe end, pipe-to-safe end, and nozzle-to-cap components. The staff accepts the proposed program for stainless steel safe ends because it conforms to the recommendations in the BWRVIP-75; however, if the safe ends contain nickel-alloy weld metals that are susceptible to SCC, BWRVIP-75 would require more frequent examinations than those specified for BWRVIP-75 Category A welds. In order for the staff to determine whether the applicant had adequately implemented BWRVIP-75, the staff requested that the applicant identify (1) the weld metal that was used for the butter, nozzle-to-safe end welds, pipe-to-safe end welds, and nozzle-to-cap welds; (2) the grade of stainless steel that was used as a safe end; and (3) the examination requirements for butter, nozzle-to-safe end welds, pipe-to-safe end welds, and nozzle-to-cap welds that are more susceptible to SCC than the BWRVIP-75 Category A welds.

The applicant, in its response dated May 25, 2005, indicated that stainless steel weld metal was used for the butter on the nozzle-to-safe end welds and that it would implement the inspection guidelines that are specified in the BWRVIP-75 report for the subject welds. Since the stainless steel weld metal is less susceptible to IGSCC than nickel-alloy weld metal, the staff concludes that inspection requirements as specified in the BWRVIP-75 guidelines will adequately identify aging degradation in a timely manner. The applicant further stated that it used nuclear grade (low carbon) stainless steel for the safe end material in recirculation and core spray systems with the exception of non-nuclear grade (i.e., standard carbon content) stainless steel safe ends in the recirculation outlet welds in Units 2 and 3. The applicant proposed to implement the BWRVIP-75 inspection guidelines, which are acceptable to the staff because they provide adequate assurance in identifying cracking due to IGSCC in a timely manner for nozzle-to-safe end welds. Since the stainless steel weld metal and nuclear grade stainless steel safe end materials (with exception noted above) are less susceptible to IGSCC, the staff concluded that the applicant's proposed inspection guidelines will adequately manage aging effects in the recirculation and core spray systems. With respect to the non-nuclear grade recirculation outlet nozzles and their welds in Units 2 and 3, the applicant stated that it will use a mechanical stress improvement (MSIP) method to mitigate IGSCC and will use Category C inspection guidelines to monitor the aging effects in these welds. The staff found the response acceptable because the applicant's proposed mitigation and inspection methods for the recirculation outlet nozzle welds will comply with the staff-approved BWRVIP-75 inspection criteria and will enable the applicant to identify IGSCC in a timely manner. Therefore, the staff’s concern described in RAI 3.1.2.1-4(C) is resolved.

3.1.2.3.9 Feedwater Nozzle

GALL AMP XI.M5, “BWR Feedwater Nozzle,” recommends that inspection requirements specified in GE-NE-523-A71-0594, “Alternate BWR Feedwater Nozzle Inspection Requirements,” be implemented for the feedwater nozzles for managing cracking due to cyclic loading for the feedwater nozzles.

The applicant included the BWR Feedwater Nozzle Program for managing the aging effect related to cracking due to cyclic loading in the feedwater nozzles at BFN. The applicant stated that the program is consistent with GALL AMP XI.M5, with no exceptions. The applicant also invoked the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, which is an established AMP. This program has appropriate requirements for inspecting the feedwater nozzle components. The applicant also stated that the program enhances the ISI specified in ASME Code Section XI with the recommendations of GE-NE-523-A71-0594. The applicant stated that it implemented the recommendations of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking,” to mitigate feedwater nozzle cracking. The applicant also stated that the feedwater nozzles had been modified to mitigate cracking by removing the stainless steel cladding and machining the safe end, nozzle bore, and inner bend radius to accept improved double-piston-ring interference-fit spargers with a forged tee design and orificed elbow discharges. The applicant indicated in the LRA that the reactor water cleanup system return lines were routed to both feedwater headers (except Unit 2, which is only routed to one feedwater header). The applicant stated that changes to plant operating procedures, such as improved feedwater control, to decrease the magnitude and frequency of temperature fluctuations had been implemented at Units 2 and 3. The applicant also indicated that similar improvements will be implemented at Unit 1 prior to the period of extended operation. SER Section 3.0.3.2.4 presents the staff's detailed review of the BWR Feedwater Nozzle Program.

In RAI 3.1.2.1-4(B), dated December 1, 2004, the staff requested that the applicant provide information on the scope and the techniques of past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections, and any other relevant information related to the identification of the aging effect in the feedwater nozzles at BFN. The staff further requested that the applicant provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the BWR Feedwater Nozzle Program.

In its response, by letter dated January 31, 2005, the applicant stated that it complied with the inspection requirements specified in the BWR Feedwater Nozzle Program. The applicant stated that it had performed UT of the feedwater nozzles and the results were acceptable, and no repairs were performed in this system. Therefore, the applicant concluded that the plant-specific experience related to feedwater nozzles has no impact on the attributes specified in the BWR Feedwater Nozzle Program. The staff reviewed the applicant’s response and found it acceptable. The applicant demonstrated that the actions taken thus far have mitigated cracking in feedwater nozzles. Therefore, the staff’s concern described in RAI 3.1.2.1-4(B) is resolved.

In RAI B.2.1.8-1, the staff stated that the BWR Feedwater Nozzle Program references GE report GE-NE-523-A71-0594, which is not the staff-approved version of the report. The staff requested that the applicant replace references to GE-NE-523-A71-0594 in LRA Sections A.1.8 and B.2.1.8 with GE-NE-523-A71-0594-A, Revision 1 which is approved by the staff. In its response to RAI B.2.1.8-1, by letter dated January 31, 2005, the applicant stated that it will revise the LRA to indicate correct GE report. In its response, by letter May 25, 2005, the applicant submitted a revised version of LRA Section A.1.8, and the BWR Feedwater Nozzle Program, which includes GE-NE-523-A71-0594-A, Revision 1.

The staff found that the implementation of ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and the BWR Feedwater Nozzle Program would be consistent with GALL AMP XI.M5 and, therefore, is acceptable. The staff's concern described in RAI B.2.1.8-1 is resolved.

3.1.2.3.10 Control Rod Drive (CRD) Return Line Nozzle

GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle," recommends that enhanced inspection requirements specified in NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," should be implemented for the CRD return line nozzles for managing the cracking due to cyclic loading for the CRD return line nozzle.

In LRA Table 3.1.2.1, the applicant referenced BWR CRD Return Line Nozzle Program, for managing the aging effect in the CRD return line. The applicant stated that the program is consistent with GALL AMP XI.M6, with no exceptions. The applicant indicated that inspections that are specified in NUREG-0619, and ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, which is an established AMP. This program has appropriate requirements for inspecting the CRD return line nozzle components.

In RAI B.2.1.9-1, dated December 1, 2004, the staff requested the applicant to provide information on the augmented inspection requirements that are specified in the NUREG-0619. The CRD return line nozzle has been capped; therefore, augmented inspection of the nozzle is not needed per NUREG-0619. The guidance in NUREG-0619 provide actions to be taken to address cracking in these nozzles; however, the aging effects for the cap and applicable weld are not covered in NUREG-0619. Therefore, the staff requested that the applicant address the following issues concerning the cap and weld that provide a pressure boundary function:

In RAI B.2.1.9-1(1) the applicant was requested to describe the configuration, location and material of construction of the capped nozzle, including the existing base material for the nozzle, piping (if piping remnants exist) and cap material, and any welds. In its response by letter dated January 31, 2005, the applicant stated that the configuration consists of a stainless steel cap welded to the original carbon steel nozzle with stainless steel weld material. The safe end and corresponding piping had been removed from the nozzle.

In RAI B.2.1.9-1(2) the applicant was requested to describe the application of the BWRVIP-75 inspection guidelines for this weld and cap. In its response to RAI B.2.1.9-1(2), by letter dated January 31, 2005, the applicant stated that the requirements of BWRVIP-75 are implemented by the BWR Stress Corrosion Cracking Program. The CRD return line nozzle welds are currently categorized (BWRVIP-75) as Category D for Unit 2 and Category C for Unit 3. The CRD return line nozzle welds are examined by the UT technique at the frequency specified by BWRVIP-75, Table 3-1 for normal water chemistry conditions. The applicant stated that it will implement the BWR Stress Corrosion Cracking Program for Unit 1 prior to the period of extended operation.

The staff reviewed the applicant's response and found it acceptable provided the applicant includes information in the LRA regarding the category (per BWRVIP-75) of the subject weld in Unit 1.

In RAI B.2.1.9-1(3) the applicant was requested to discuss the applicability of the event at Pilgrim (leaking weld at a capped nozzle, September 30, 2003) to BFN. The staff issued IN 2004-08, dated April 22, 2004, which states that the cracking occurred in an alloy 82/182 weld that had previously been repaired at the Pilgrim unit. According to IN 2004-08, the Pilgrim CRD return line nozzle is made of SA-508, Class 2 low-alloy steel, while the CRD return line cap is made of Alloy 600. The subject weld is fabricated with Alloy 82/182 material, and the nozzle side of the weld is buttered with Alloy 182 material. In addition, Pilgrim had initial weld deficiencies (lack of fusion) that required weld repair. The staff also requested that the applicant provide any plant experience with leakage at the capped nozzle, the past inspection techniques used, results obtained, and mitigative strategies imposed. The staff requested that the applicant provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the BWR CRD Return Line Nozzle Program.

In its response, by letter dated January 31, 2005, the applicant stated that the event at Pilgrim was determined not to be applicable. The materials of construction of the nozzle-to-cap weld at BFN is stainless steel. The welds were completed without recordable indications. Plant experience for Units 2 and 3 indicates that there has been no leakage at the capped CRD return line nozzles. Ultrasonic exams have been performed with no reportable indications. The Unit 3 capped CRD return line nozzle weld had MSIP performed to mitigate IGSCC, which changed the frequency of inspection. The examination information related to this item is described in RAI B.2.1.9-1(2). The plant-specific experience related to the CRD return line nozzle has no impact on the attributes specified in the BWR CRD Return Line Nozzle Program.

The staff reviewed the applicant’s responses and found them acceptable, in part, because the improved RCS water chemistry and MSIP (for Unit 3) should provide adequate mitigation to preclude IGSCC. However, the staff found that, unlike weld metal Alloy 182, austenitic stainless steel weld metal (with a minimum delta ferrite) is less susceptible to IGSCC. In addition, low carbon austenitic stainless steel material (L grade) is less susceptible to IGSCC than non-L grade austenitic stainless steel.

In order for the staff to determine whether the applicant had adequately implemented BWRVIP-75 for the Category A CRD return line nozzle welds, the staff requested that the applicant identify (1) the delta ferrite in the weld metal, (2) the grade of stainless steel that was used for the CRD return line cap, (3) the examination requirements for CRD return line welds that meet BWRVIP-75, and (4) plans to implement MSIP in Units 1 and 2.

In its response dated May 25, 2005, the applicant indicated that stainless steel weld metal with a minimum of eight percent delta ferrite was used for the CRD return line nozzle-to-cap welds and that it will implement inspection guidelines as specified in the BWRVIP-75 report for the subject welds. The applicant proposed to implement BWRVIP-75 inspection guidelines, which are acceptable to the staff because they provide adequate assurance in identifying cracking due to IGSCC in a timely manner for nozzle-to-safe end welds. Since the stainless steel weld metal with eight percent delta ferrite is less susceptible to IGSCC than nickel-alloy weld metal, the staff concluded that inspection requirements as specified in the BWRVIP-75 guidelines will adequately identify aging degradation in a timely manner.

The applicant further stated that it used low carbon grade stainless steel for the CRD return line cap materials. Since the stainless weld metal and low carbon grade stainless steel CRD return line cap materials are less susceptible to IGSCC, the staff concluded that the applicant's proposed inspection guidelines will adequately manage the aging effect in the CRD return line nozzle-to-cap welds. Regarding the application of MSIP as a mitigative technique to improve resistance to IGSCC, the applicant stated that it will use the following plan to implement MSIP for CRD return line nozzle-to-cap welds: (1) MSIP and BWRVIP-75 inspection guidelines will be implemented for Unit 1 welds prior to restart; (2) no MSIP will be used for Unit 2 welds; however, BWRVIP-75, Category D inspection guidelines will be implemented for these welds; and, (3) MSIP was used in Unit 3 welds and the BWRVIP-75, Category C inspection guidelines will be use for these welds. The staff found the response acceptable because the applicant's proposed mitigation and inspection methods for the CRD return line nozzle-to-cap welds will comply with the staff approved BWRVIP-75 inspection criteria, and will enable the applicant to identify IGSCC cracking in a timely manner. Therefore, the staff's concern described in RAI B.2.1.9-1 is resolved.

The staff found that the implementation of the BWR CRD Return Line Nozzle Program and ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program for the CRD return lines would be consistent with the GALL AMP XI.M6, and is, therefore, acceptable. SER Section 3.0.3.1.5 presents the staff's detailed review of this AMP.

3.1.2.3.11 Reactor Vessel Penetrations

AMPs recommended by the GALL Report for managing cracking due to IGSCC for the RV penetrations are XI.M8, "BWR Penetration," and XI.M2, "Water Chemistry." The GALL AMPs for the RV penetrations include implementation of guidelines specified in BWRVIP-49, "Instrumentation Penetration Inspection and Flaw Evaluation Guidelines," and reactor coolant water chemistry in accordance with the guidelines of BWRVIP-29, "BWR Water Chemistry Guidelines," (EPRI TR-103515). In addition to these requirements, the GALL program XI.M8, "BWR Penetration," recommends that inspection and flaw evaluation guidelines specified in BWRVIP-27, "BWR Standby Liquid Control System/Core Plate delta P Inspection and Flaw Evaluation Guidelines," should be implemented for the RV penetrations.

In LRA Table 3.1.2.1, the applicant indicated that nickel-alloy and stainless steel materials in the RV penetration components, when exposed to a treated-water environment, experience cracking due to SCC. The applicant included the BWR Reactor Penetration Program for managing the aging effect related to cracking due to SCC in the RV penetrations. The applicant stated that this AMP is consistent with GALL AMP XI.M8 with no exceptions. The BWR Reactor Penetration Program recommends the implementation of the staff's approved versions of BWRVIP-27, BWRVIP-49, and ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, which is an established AMP. This program has appropriate requirements for inspecting the BWR RV penetrations (i.e., category B-E for pressure-retaining partial penetration welds; category B-D for full penetration nozzle-to-vessel welds; category B-F for pressure retaining dissimilar metal nozzle-to-safe end welds; and category B-J for similar metal nozzle-to-safe end welds). The extent and schedule of inspection prescribed by the ASME Code Section XI ISI Program is designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. These inspections can reveal crack initiation and growth and leakage of coolant due to SCC. In addition, the applicant indicated that the Chemistry Control Program, which is based on EPRI Report TR-103515-R2, (the 2000 revision of "BWR Water Chemistry Guidelines"), will be applied. The staff found the EPRI TR-103515-R2 acceptable because the program is based on updated industry experience, and plant-specific and industry-wide operating experience confirm the effectiveness of the RCS chemistry program.

In RAI 3.1.2.1-5(B), dated December 1, 2005, the staff requested that the applicant provide any previous plant-specific experience regarding the cracking due to SCC and IGSCC in dissimilar metal welds of RV penetrations, and the method and frequency of inspection for managing this aging effect. In its response to RAI 3.1.2.1-5(B), by letter dated January 31, 2005, the applicant stated that the following penetrations are inspected during the ASME Code Section XI, IWB-2500, Code Category B-P system leakage test during each refuel outage: (1) CRD stub tubes; (2) instrumentation nozzle/nozzle safe ends; (3) standby liquid control nozzles; (4) jet pump instrumentation nozzles; (5) drain line nozzles; and (6) in-core monitor housing penetrations.

The applicant also stated that no cracking of the dissimilar metal penetration welds have been identified thus far at BFN. In addition, the applicant stated that the improvements in the RCS Chemistry Control Program would mitigate the IGSCC of the RV penetration welds. The applicant stated that the plant-specific experience related to the RV penetrations has no impact on the attributes of the BWR Penetrations Program.

The staff reviewed the response to the RAI 3.1.2.1-5(B) and found it acceptable. Implementation of the improved water chemistry and ISI programs as specified in the BWR Penetrations Program, would enable the applicant to manage the aging effect due to IGSCC effectively during the extended period of operation, and would be consistent with GALL AMPs XI.M8 and XI.M2. Therefore, the staff’s concern in RAI 3.2.1.2-5(B) is resolved.

3.1.2.1.12 Reactor Head Closure Studs

GALL AMP XI.M3, “Reactor Head Closure Studs,” recommends that preventive actions specified in RG 1.65, “Materials and Inspections for RV Closure Studs,” should be implemented for managing the cracking due to SCC for the reactor head closure studs. SER Section 3.0.3.1.4 present the staff's detailed review of this AMP.

In LRA Table 3.1.2.1, the applicant indicates that the Reactor Head Closure Studs Program, which is consistent with GALL AMP XI.M3, will be implemented to monitor the aging effect due to SCC of the reactor head closure studs.

The applicant stated that the following requirements will be implemented for the Reactor Head Closure Studs Program.

- ISI in conformance with the requirements of the ASME Code Section XI, Subsection IWB, Table IWB 2500-1.
- Mitigation of cracking is achieved by complying with the requirements of Regulatory Guide 1.65, “Materials and Inspections for RV Closure Studs.” The applicant stated that approved lubricants will be used to minimize the potential for cracking of the non-metal-plated reactor head closure studs.

The applicant stated that industry experience indicated that SCC occurred in metal-plated BWR reactor head closure studs. The applicant stated that there are no metal-plated reactor head closure studs in use, and approved lubricants are used to prevent seized studs or nuts. The applicant claimed that with the lack of metal plating and preventive use of approved lubricants, Reactor Head Closure Studs Program has been effective in reducing the probability of SCC of the reactor head closure studs.

The applicant concluded in its LRA that the Reactor Head Closure Studs Program provides reasonable assurance that aging effects due to cracking in the reactor head closure studs is adequately managed so that their intended functions, consistent with the CLB, are maintained during the period of extended operation.

The staff concluded that the reactor head closure studs are less likely to experience aging effects related to SCC, because these closure studs are not metal plated and approved lubricants are used for their maintenance. The staff found the implementation of Reactor Head Closure Studs Program is acceptable. Presence of aging effects can be identified by frequent inspections dictated by the Reactor Head Closure Studs Program. In addition, compliance with RG 1.65 requirements provides adequate assurance in maintaining the integrity of the RV studs. The staff concluded that implementation of the aforementioned requirements provides assurance that the aging effect associated with SCC is adequately managed by the applicant.

3.1.2.3.13 Bolting for Reactor Vessel Vents and Drains

In RAI 3.1.2.3-1(A), dated December 1, 2004, the staff stated that GALL AMP XI.M18, “Bolting Integrity Program,” is recommended for managing the aging effects for the bolting in the RV vents and drains. In LRA Table 3.1.2.3, the applicant indicates that the Bolting Integrity Program, which is consistent with GALL AMP XI.M18, will be implemented to monitor the aging effects of the bolting in RV vents and drains. LRA Table 3.1.2.3 and the Bolting Integrity Program do not identify SCC as an aging effect for these bolts. Therefore, the staff requested that the applicant address the aging effect due to SCC in the bolts of the RV vents and drains.

In its response, by letter January 31, 2005, the applicant stated that SCC can occur in high yield strength (greater than 150 ksi) bolted closures in BWRs when they are exposed to a corrosive environment, typically attributed to leakage of pressure boundary joints or exposure to wetted ambient environments or due to the use of thread lubricant containing molybdenum disulfide (MoS_2). High yield strength, heat-treated alloy steel bolting materials are not specified for flanged connections. High strength bolting in vendor-supplied equipment has not been identified for mechanical components (such as pump casing studs or valve body/bonnet studs) where the material specifications are available. The applicant stated that a review of the BFN operating experience did not identify any instances where mechanical component failure was attributable to SCC of high strength bolting. Therefore, loss of bolting function due to SCC of bolted joints of mechanical equipment is not expected and no aging management is required for the period of extended operation. Since there are no high-yield strength bolts in the RV vents and drains at BFN, the staff concluded that no AMP is required to monitor the aging effect due to SCC in bolting in reactor vents and drains. Therefore the staff’s concern described in RAI 3.1.2.3-1(A) is resolved.

3.1.2.3.14 Loss of Materials in Low Alloy Steel or Carbon Steel Reactor Vessel Components that are exposed Externally to Inside (Atmospheric) Environments

The applicant identified in Table 3.1.2.1 of the LRA no aging effects, but included references related to the GALL Report Volume 2, Table IV. A1 for carbon and low-alloy steel materials of the following RV components exposed externally to inside (atmospheric) environments.

- other external attachment welds to the reactor vessel
- reactor vessel heads, flanges, and shell
- reactor vessel nozzles
- reactor vessel nozzles and safe ends
- reactor vessel penetrations
- reactor vessel internals CRD housing
- bolting in reactor vessel vents, drains and the recirculation system

The staff reviewed the applicant's evaluation to determine whether it adequately addressed the issue of uniform corrosion of the carbon and low-alloy steel RV components when they are exposed externally to inside (atmospheric) environments. According to SRP-LR Section 3.4.2.2.4, loss of material due to general corrosion can occur on the external surfaces of carbon and low-alloy steel RV components exposed to operating temperature less than 212 °F. Since the operating temperature of the BWR vessel is greater than 212 °F, the loss of material due to general corrosion is not likely to occur in carbon and low-alloy steel RV components. In addition, the external surface of the carbon and low-alloy steel RV components are exposed to inside (atmospheric) environment that does not contain any aggressive ions resulting in loss of material due to corrosion.

In RAIs 3.1.2-1, 3.1.2.1-4(A), and 3.1.2.1-5(A), dated December 1, 2004, the staff requested that the applicant provide an explanation as to why the loss of material due to corrosion is not considered as an aging effect for carbon and low-alloy steel vessel attachment welds; vessel heads, flanges, and shells; vessel nozzles and safe ends; vessel penetrations; and bolting in vessel vents, and drains for Unit 1.

In its response to RAIs 3.1.2-1, 3.1.2.1-4(A), and 3.1.2.1-5(A), by letter dated January 31, 2005, the applicant indicated that for Unit 1 degradation due to corrosion of all the aforementioned RV components would be verified under the Unit 1 restart program. The applicant also stated that it will perform further inspection of the subject RV components followed by replacement (if required) of the degraded components that are identified by this inspection. The staff found that the applicant's implementation of inspection and replacement programs (when necessary) provides reasonable assurance that the aging effect due to corrosion of carbon and low-alloy steel penetrations for Unit 1 will be adequately managed so that the intended function(s) will be maintained with the CLB for the period of extended operation.

Therefore, the staff found that these components do not experience any of the aforementioned aging effects when they are exposed externally to an inside (atmospheric) environment. The staff concluded that the applicant's determination to exclude these aging effects in LRA Table 3.1.2.1 for the aforementioned RV components is acceptable. Therefore the staff’s concern described in RAIs 3.1.2-1, 3.1.2.1-4(A), and 3.1.2.1-5(A) is resolved.

3.1.2.3.15 Distortion/plastic deformation due to stress relaxation and loss of material due to mechanical wear - Reactor head closure studs and nuts; bolting in RV vents, drains and the recirculation system

In LRA Table 3.1.2.1, the applicant addressed distortion and plastic deformation due to stress relaxation and loss of material due to mechanical wear as aging effects in reactor head closure studs and nuts. The applicant proposed to use the Reactor Head Closure Stud Program, which, in turn, invokes the requirements of GALL AMP XI.M3 to monitor this aging effect. The applicant reiterated that the aforementioned aging effect is adequately managed by the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program.

In RAI 3.1.2.1-2, dated December 1, 2004, the staff requested that the applicant identify any plant-specific aging effects due to distortion/plastic deformation resulting from stress relaxation and loss of material due to mechanical wear for the reactor closure studs and nuts.

In its response to RAI 3.1.2.1-2, by letter dated January 31, 2005, the applicant stated that it has not identified any RV closure stud or nut degradation resulting in distortion/plastic deformation due to stress relaxation or loss of material due to mechanical wear. The applicant also stated that no RV closure studs or nuts have been replaced for this reason. Two studs were replaced in Unit 2 during the Unit 2 Cycle 4 refueling outage. These were replaced because of physical thread damage. From discussions with plant personnel present at that time, this damage was the result of impacts during handling and refueling operations, and not the result of inservice stress or wear. Based on this, the applicant stated that there was no impact on the attributes specified in the Reactor Head Closure Studs Program. The staff concluded that the proposed ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and Reactor Head Closure Studs Program for the reactor closure studs are consistent with GALL AMP XI.M3, and the subject aging effects are adequately managed by the applicant for the period of extended operation. The staff finds this response acceptable, and its concern related to RAI 3.1.2.1-2 is resolved.

In LRA Table 3.1.2.3, the applicant addressed loss of bolting function due to wear as an aging effect in RV vents and drains and the recirculation system. The applicant proposed to use the Bolting Integrity Program for monitoring this aging effect, which in turn, invokes the requirements of GALL AMP XI.M18. GALL AMP XI.M18 requires application of ASME Code Section XI Subsection IWB, Table IWB 2500-1 for the bolts that are included in the ASME Code Section XI Program to monitor this aging effect. In addition, the aging effects for the SR bolting are mitigated by NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation Failure in Nuclear Power Plants." For bolts that are not included in the ASME Section XI program, the applicant proposed to use the Systems Monitoring Program. The staff concluded that the implementation of the Bolting Integrity Program and Systems Monitoring Program, and compliance with GALL AMP XI.18 will provide reasonable assurance that loss of bolting function due to wear in RV vents and drains and the recirculation system is adequately managed so that their intended functions, consistent with the CLB, are maintained during the period of extended operation.

In RAI 3.1.2.3-1(B), dated December 1, 2004, the staff requested that the applicant provide information on the previous plant-specific experience of loss of bolting function due to wear in the RV vents and drains system. The staff also requested that the applicant provide information on the scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections and any other relevant information related to the identification of this aging effect of the bolts in RV vents and drains. In addition, the staff requested that the applicant provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the Bolting Integrity Program.

In its response to RAI 3.1.2.3-1(B), by letter dated January 31, 2005, the applicant stated that aging effect due to wear was conservatively identified to be an aging effect that requires management for the period of extended operation for pressure boundary bolting in RV vents and drains. The applicant also stated that these bolts are inspected in accordance with ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program inspection requirements, and the Systems Monitoring Program. The Systems Monitoring Program performs an entire system inspection once per fuel cycle and includes visual inspections for evidence of material condition and bolting torque relaxation. The Systems Monitoring Program documents failures in either the maintenance work order or plant corrective action program, as appropriate. The applicant indicated that so far, no instances of RV vents and drains bolting failure due to wear have been identified. The staff finds this response acceptable, and its concern related to RAI 3.1.2.3-1(B) is resolved.

In RAI 3.1.2.4-1(A), dated December 1, 2004, the staff requested that the applicant provide information on the previous plant-specific experience of loss of bolting function due to stress relaxation in the RV recirculation system. The staff also requested that the applicant provide information on the scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections, and any other relevant information related to the identification of this aging effect of the RV recirculation system bolts. In addition, the staff requested that the applicant provide information as to how the plant-specific experience related to this aging effect impacts the attributes specified in the Bolting Integrity Program.

In its response to RAI 3.1.2.4-1(A), by letter dated January 31, 2005, the applicant stated that it inspected the reactor water recirculation pump closure bolting in accordance with the requirements of ASME Section XI, Table IWB-2500-1, Category B-G-1. The inspection methods included visual examination and UT, and the results were acceptable. Therefore, the applicant did not perform any repair on the reactor recirculation pump closure bolting. The applicant stated that implementation of AMP B.2.1.16, and compliance with the recommendations of NUREG-1339 and EPRI NP-5769 provide adequate assurance that the aging effect due to stress relaxation in the bolting of the RV recirculation system is effectively managed for the extended period of operation.

The staff reviewed the applicant's responses to the above RAIs, and concluded that the implementation of ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, Bolting Integrity Program, and Systems Monitoring Program is consistent with GALL AMP XI.M18 and the subject aging effects for bolting in RV vents, drains and the recirculation system are adequately managed at BFN. Therefore, the staff’s concerns described in the above RAIs are resolved.

3.1.2.3.16 Crack Initiation and Growth Due to Stress Corrosion Cracking, Fatigue and Cyclic Loading

The staff's evaluation of the aging effect due to cyclic loading and fatigue is discussed in SER Section 3.1.2.2.4.

AMPs recommended by the GALL Report for managing cracking due to IGSCC for the RV internal components are XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," XI.M2, "Water Chemistry," and XI.M9, "BWR Vessel Internals." AMP XI.M9 includes implementation of guidelines specified in the staff-approved BWRVIP documents for a given component.

In LRA Table 3.1.2.2, the applicant identified SCC as an aging effect in (1) RVIs core shroud and core plate, (2) RVIs core spray and feedwater spargers, (3) RVIs control rod housing and dry tubes and guide tubes, (4) RVIs jet pump assemblies, and (5) RVIs top guide.

In LRA Table 3.1.2.2, the applicant stated that the aging effect due to SCC in the aforementioned components is managed by (1) Boiling Water Reactor Vessel Internals Program, (2) ASME Code Section XI Subsections IWB, IWC, and IWD ISI Program, and (3) the Chemistry Control Program. The applicant stated that continued implementation of these AMPs provides reasonable assurance that the aging effects due to SCC, fatigue, and cyclic loading will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

In RAI 3.1.2.1-6(A), dated December 1, 2004, the staff requested that the applicant provide information on the scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, and frequency of the inspections of the AHCs. In response to RAI 3.1.2.1-6(A), by letter dated January 31, 2005, the applicant stated that the Unit 1 core shroud AHCs currently have indications of cracking and will be replaced with a bolted design in lieu of a welded design prior to Unit 1 restart. Units 2 and 3 AHCs have no reportable indications. In addition, the applicant stated that the improvements in the RCS Chemistry Control Program would enable the mitigation of IGSCC of the AHCs.

In RAI B.2.1.12-1(C), dated December 1, 2004, the staff requested the applicant to provide information regarding any prior augmented UT for the AHCs as required by GALL Report Section IV-B1.1.4. In its response, by letter January 31, 2005, the applicant stated that the AHCs are examined in accordance with GE SIL No. 462, Revision 1. The GE SIL allows for inspection of the AHCs either by UT or top-surface visual (VT-1) inspection. The applicant has always used the UT technique, as this methodology provides superior flaw detection and allows for a longer reinspection interval. Due to tooling constraints, a top-surface enhanced VT-1 (EVT-1), which is superior to the visual examination guidelines of GE SIL No. 462, was performed for Unit 3 AHCs. The applicant stated that prior to the period of extended operation, it will implement visual inspection of the AHCs and inspection of the AHC welds by UT, unless tooling constraints prohibit performance of a UT. In the event tooling constraints prohibit inspection by UT, the inspection will be performed by EVT-1. The applicant proposed to inspect the AHCs utilizing the BWR Vessel Internals Program rather than the ASME Code Section XI ISI Program currently specified in the GALL Report. SER Section 3.0.3.2.7 presents the staff's detailed review of this AMP.

Since the GALL Report Section IV-B1.1.4 requires UT of AHC welds, the staff requested that the applicant revise BWR Vessel Internals Program and LRA Section A.1.12 to include UT for Units 2 and 3 AHC welds to the maximum extent possible. The staff requested that the applicant identify its previous experience on the extent to which UT was performed on the AHC welds.

The applicant, in its response dated May 25, 2005, stated that Unit 1 welded AHCs will be replaced by a bolted design thereby eliminating the need for UT. However, Units 2 and 3 will still have welded AHCs and they require UT examination. The applicant stated that UT examinations had been performed on the AHC welds in Units 2 and 3, and thus far no indications had been identified. The applicant stated that it will perform UT on AHC welds at

Units 2 and 3 unless tooling constrains prohibit inspections by UT, in which case it will perform EVT-1 examinations. The applicant stated that it will obtain prior approval from the staff if EVT-1 is substituted for UT examination of the welded AHCs at Units 2 and 3. The staff found this response acceptable, because previous UT examinations of AHC welds at Units 2 and 3 indicated no evidence of cracks and as such there is no evidence of active degradation in the AHC welds at Units 2 and 3. Additionally, the applicant stated that it will perform UT examinations on accessible AHC welds and EVT-1 examinations in inaccessible AHC welds, and these examinations will adequately identify the cracks in AHC welds at Units 2 and 3. The staff accepts the applicant's response as a commitment and concludes that it should be included in the commitment tables in lieu of LRA Section A.1.12. Based on its review, the staff’s concerns described in RAIs 3.1.2.1-.6(A), and B-2.1.12-1(C) are resolved.

In RAI 3.1.2.1-6(B), dated December 1, 2004, the staff requested that the applicant provide an explanation for excluding the aging effect due to IASCC for the core shroud and core plate. In its response to RAI 3.1.2.1-6(B), by letter dated January 31, 2005, the applicant stated that it will include the aging effect due to IASCC in LRA Table 3.1.2.2, and this aging effect is managed by implementing the ASME Code Section XI Subsections IWB, IWC, and IWD and Chemistry Control Programs. The BWR Vessel Internals Program invokes inspection requirements specified in BWRVIP-76, "Boiling Water Reactor Core Shroud Inspection and Flaw Evaluation Guidelines," which is currently being reviewed by the staff. In the BWR Vessel Internals Program, the applicant stated that it will comply with all the requirements that will be specified in the staff's SER on the BWRVIP-76 report, and will complete all the license renewal applicant action items of this SER when it is issued. The staff reviewed the response and found it acceptable because the implementation of the inspections as mandated by the ASME Code Section XI Subsections IWB, IWC, and IWD Program and BWRVIP-76 (pending staff's approval) should identify any cracking due to IASCC in a timely manner so that the intended function of the subject component is maintained during the extended period of operation.

In RAI 3.1.2.1-6(C), dated December 1, 2004, the staff requested the applicant to provide information regarding the plant-specific experience related to IGSCC cracking of the stainless steel and nickel-alloy components in the core shroud and AHCs, and the effective AMP that will be implemented on these systems. In its response to RAI 3.1.2.1-6(C), by letter dated January 31, 2005, the applicant stated that indications have been reported in Unit 1 core shroud welds H-1, H-2, H-3, H-4, and H-5. Core shroud welds H-6 and H-7 have not been examined due to interference from vibration sensing lines. These welds will be UT examined prior to Unit 1 restart. Indications have been reported in Unit 2 core shroud welds H-1, H-2, H-3, H-5, H-6, and H-7. Indications have been reported in Unit 3 core shroud welds H-1, H-2, H-3, H-4, H-5, and H-7. The applicant stated that the aging effect due to IGSCC is managed by AMPs BWR Vessel Internals, ASME Code Section XI Subsections IWB, IWC, and IWD, and Chemistry Control Programs. The staff finds this response acceptable, and its concern related to RAI 3.1.2.1-6(C) is resolved.

In RAI 3.1.2.1-6(D), dated December 1, 2004, the staff requested the applicant to address the plant-specific experience regarding sudden increases in RCS water conductivity due to a leak in condensate and/or reactor water clean up systems, and the impact of these sudden conductivity excursions on the IGSCC of core shroud welds. In its response to RAI 3.1.2.1-6(D), by letter dated January 31, 2005, the applicant stated that there had been no increase in conductivity in RCS water due to leaks in condensate and/or reactor water clean up systems in the previous five years. The staff found that in the absence of any increase in RCS water conductivity, and with the addition of hydrogen/noble metal to the RCS water, the growth of existing IGSCC in the core shroud welds will be mitigated. The staff finds this response acceptable, and its concern related to RAI 3.1.2.1-6(D) is resolved

In RAI 3.1.2.1-6(E), dated December 1, 2004, the staff requested the applicant to provide information on verification methods to monitor the effectiveness of the HWC/NMCA program, the methodology of ensuring hydrogen availability in the core shroud region, monitoring of its availability with ECP probes, and the validity of using secondary parameters (e.g., main steam/feedwater oxygen levels) to assess the hydrogen availability at core shroud welds. In its response to RAI 3.1.2.1-6 (E), by letter dated January 31, 2005, the applicant stated that an NMCA with a conservative hydrogen/oxygen (H_2/O_2) molar ratio is maintained to ensure hydrogen availability in the core shroud region. The applicant stated that it would not utilize ECP probes; therefore, alternate means are used to monitor ECP. The applicant proposed to use reactor water H_2/O_2 molar ratio of greater than four for power operation. The staff reviewed the response and found it acceptable because, in the absence of ECP measurements, maintaining a H_2/O_2 molar ratio of greater than four would be effective in mitigating IGSCC in core shroud welds.

The staff found that the implementation of the improved water chemistry and ISI programs in conjunction with the inspection guidelines specified in the BWRVIP-76 report (pending staff's approval) would enable the applicant to manage the aging effect due to IGSCC effectively during the extended period of operation, and would be consistent with GALL AMPs XI.M1, XI.M2 and XI.M9.

In RAI 3.1.2.2-7(A), dated December 1, 2004, the staff requested the applicant to provide an explanation for excluding the aging effect due to IASCC for the core spray spargers and piping in LRA Table 3.1.2.2. According to GALL Report Section IV B1.3-a, an AMP is required for monitoring IASCC in core spray spargers and piping. In its response, by letter dated January 31, 2005, the applicant stated that it will include aging effect due to IASCC in LRA Table 3.1.2.2, and this aging effect is managed by implementing the ASME Code Section XI Subsections IWB, IWC, and IWD, BWR Vessel Internals, and Chemistry Control Programs.

In RAI 3.1.2.2-7(B), dated December 1, 2004, the staff requested the applicant to provide information on the type and extent of inspections to identify IGSCC and the mitigation techniques for core spray piping and spargers at Units 2 and 3. In its response, by letter dated January 31, 2005, the applicant stated that the inspections (the type and extent) were performed in accordance with the requirements of BWRVIP-18, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines," and ASME Code Section XI Subsections IWB, IWC, and IWD, BWR Vessel Internals. The applicant stated that thus far no cracking was identified in the core spray system with the following exceptions. The applicant stated that it identified cracking in the elbow-to-shroud pipe and collar-to-shroud welds in downcomer "C" in Unit 3, which was subsequently replaced with a bolted piping assembly as a corrective action. The applicant identified cracking in Unit 3 core spray sparger adjacent to the T-boxes, which was repaired by welded brackets at both T-boxes. The applicant indicated that mitigation of IGSCC in core spray piping and spargers would be achieved by the implementation of HWC/NMCA.

The staff, after reviewing BWRVIP-18, concluded that core spray piping and spargers are not adequately protected by the HWC/NMCA. However, implementation of the inspection guidelines as required by BWRVIP-18 and ASME Code Section XI Subsections IWB, IWC, and IWD, will inadequately identify cracking in a timely manner. Therefore, the staff concluded that the type and extent of inspections mandated by BWRVIP-18 and the ISI Program should adequately identify cracking (without taking any credit for HWC/NMCA) in core spray piping and spargers in a timely manner so that their intended function is maintained during the period of extended operation. Since the applicant is implementing the ASME Code Section XI Subsections IWB, IWC, and IWD, BWR Vessel Internals Program and Chemistry Control Program, which are consistent with the GALL AMP XI.M9, the staff found that the applicant had demonstrated that the effects of aging in core spray piping and spargers will be adequately managed for the period of extended operation.

In RAI 3.1.2.2-8(A), dated December 1, 2004, the staff requested the applicant to provide an explanation for excluding the aging effect due to IASCC for the CRD housing dry tubes and guide tubes in Table 3.1.2.2 of the LRA. In its response, by letter dated January 31, 2005, the applicant stated that it will include aging effect due to IASCC in LRA Table 3.1.2.2, and that this aging effect is managed by implementing ASME Code Section XI Subsections IWB, IWC, and IWD, BWR Vessel Internals Program and Chemistry Control Program. BWR Vessel Internals Program in turn invokes inspection requirements specified in BWRVIP-47, "Boiling Water Reactor Lower Plenum Inspection and Flaw Evaluation Guidelines." The staff reviewed the response and found it acceptable because the implementation of the inspections as mandated by the ASME Code Section XI Subsections IWB, IWC, and IWD Program and BWRVIP-47 should identify any cracking due to IASCC in a timely manner so that the intended function of the subject component is maintained during the period of extended operation. Therefore, the staff's concern described in RAI 3.1.2.2-8(A) is resolved.

In RAI 3.1.2.2-8(B), dated December 1, 2004, the staff requested the applicant to provide information regarding the past plant-specific experience related to IGSCC in the nickel-alloy housing guide tubes and dry tubes and their subsequent replacement with crack-resistant materials at Units 2 and 3. The staff also requested that the applicant provide its plan for the replacement of Unit 1 dry tubes and guide tubes. In its response, by letter dated January 31, 2005, the applicant stated that all 12 Unit 2 and 3 radiation monitor dry tubes had been replaced with a crevice-free design in the plunger area. Additionally, the material in the plunger area had been changed from 304 stainless steel to 304L stainless steel, making the new dry tubes less susceptible to IGSCC.

The applicant in its response dated May 25, 2005, stated that it will replace Unit 1 dry tubes prior to restart. However, the applicant must commit to replace all Unit 1 dry tubes prior to restart. This commitment would be contained in a tracking process either for Unit 1 restart or license renewal.

Based on its assessment of Unit 2 Cycle 7 refueling outage and Unit 3 prior to its restart in 1995 (see RAI response dated December 1, 2004), the applicant found that the plant-specific experience related to the dry tubes has no impact on the attributes specified in the BWR Vessel Internals Program and BWRVIP-47. The staff reviewed the applicant's response and concluded that the replacement of the dry tubes material that is more IGSCC resistant combined with new crevice-free design provides adequate assurance that the aging effect due to IGSCC in these components is adequately managed for the period of extended operation. The staff found this response acceptable, and its concern related to RAI 3.1.2.2-8(B) is resolved.

In RAI 3.1.2.2-8(C), dated December 1, 2004, the staff requested that the applicant provide information regarding the plant-specific experience related to IGSCC in furnace-sensitized stainless steel stub tubes (if any) at BFN, and the method and frequency of inspections to identify this aging effect. In its response to RAI 3.1.2.2-8(C), by letter dated January 31, 2005, the applicant stated that BFN does not have furnace-sensitized stainless steel stub tubes and the stub tubes are manufactured from a nickel alloy. The applicant also stated that there have been no repairs associated with the CRD stub tubes, and improvements in the BWR Chemistry Control Program help mitigate aging and degradation of the lower plenum components. Based on this assessment, the applicant stated that the plant-specific experience related to the stub tubes has no impact on the attributes specified in the BWR Vessel Internals Program and BWRVIP-47 as no degradation has been identified. The staff concurred with the applicant's response and found it acceptable. Therefore, the staff’s concern described in RAI 3.1.2.2-8(C) is resolved.

In RAI 3.1.2.2-8(D), dated December 1, 2004, the staff requested that the applicant provide information regarding the plant-specific experience related to IGSCC cracking in nickel-alloy weld metals that were used for the CRD stub tubes, and the method and frequency of inspections to identify this aging effect. In its response, by letter dated January 31, 2005, the applicant identified the following locations associated with the lower plenum that have nickel-alloy weld metal.

- CRD housing-to-stub tube weld
- CRD stub tube-to-RV weld
- In-core housing-to-RV lower head penetration weld
- In-core guide tube-to-in-core housing weld

The applicant stated that its AMR does not identify an inspection of the listed welds, and no cracking has been identified at BFN for the listed nickel-alloy welds. The applicant also stated that the improvements in the BWR Chemistry Control Program help mitigate aging and degradation of the lower plenum components. Therefore, the applicant claimed that the plant-specific experience related to the lower plenum nickel-alloy welds has no impact on the attributes specified in the BWR Vessel Internals Program and BWRVIP-47 as no degradation has been identified. The staff found the applicant's response acceptable.

The staff concluded that the implementation of the inspection requirements as mandated by the ISI program and the staff's approved BWRVIP-47 report will provide reasonable assurance that IGSCC in the lower plenum welds can be identified in a timely manner, so that the intended function of the subject component is maintained during the period of extended operation.

In RAI 3.1.2.2-10, dated December 1, 2004, the staff requested the applicant to provide an explanation for excluding the aging effect due to IASCC for the top guide. The applicant in its response indicated that it will include IASCC as an aging effect for the top guide in LRA Table 3.1.2.2. SER Section 4.7.6 on TLAA discusses the impact of IASCC and multiple failures of the top guide grid beams at BFN.

The staff requested that the applicant in its LRA provide the AMR for the jet pump thermal sleeve welds in order to comply with the requirement specified in BWRVIP-41, Appendix A, paragraph A.2, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," report. In its response dated May 25, 2005, the applicant stated that it implemented the Chemistry

Control Program and the BWR Vessel Internals Program to monitor the aging effects in jet pump thermal sleeve welds. The applicant stated that the inspection requirements of the BWRVIP-41 report are included in the BWR Vessel Internals Program; and that they will adequately manage aging degradation due to fatigue in jet pump thermal sleeve welds. The applicant further stated that the jet pump thermal sleeve welds are not inspectible with existing techniques; however, it will implement an inspection technique that is currently being developed by the BWRVIP, when available. The staff found this response acceptable because the applicant has committed to implement BWRVIP-41 and the BWRVIP is currently developing an inspection technique that will enable the applicant to adequately identify cracking due to fatigue or IGSCC. Therefore, the staff’s concern described in RAI 3.1.2.2-10 is resolved.

3.1.2.3.17 Change in Material Properties and Reduction in Fracture Toughness Due to Thermal Aging and Neutron Irradiation Embrittlement

The AMP recommended by the GALL Report for managing the susceptibility of CASS components to thermal aging embrittlement and neutron irradiation embrittlement is AMP XI.M13, “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS).”

In LRA Table 3.1.2.2, the applicant stated that the aging effects due to change in material properties as a result of thermal and neutron embrittlement of the CASS RVIs jet pump assemblies will be managed by the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program, ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, Boiling Water Reactor Vessel Internals Program, and the inspection guidelines that are provided in the BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw evaluation guidelines," which have been approved by the staff. The implementation of these programs is consistent with the GALL AMP XI.M13, and the applicant did not take any exception to the requirements of the GALL Report. The applicant incorporated a screening criterion that establishes susceptibility of CASS components to thermal aging based on casting method, molybdenum content, and ferrite percentage.

In RAI 3.1.2.2-9, dated December 1, 2004, the staff requested the applicant to provide information on the existing (if any) CASS jet pump components, the type of casting, composition of the CASS (i.e., molybdenum content and delta ferrite values), previous plant-specific experience regarding the cracked components with subsequent inspection of any cracked CASS jet pump components due to neutron and thermal embrittlement, and any technical specification changes related to jet pump components.

In its response, by letter dated January 31, 2005, the applicant indicated that the CASS jet pump components were manufactured to ASTM A351, grade CF8. These castings are low molybdenum and the maximum calculated delta ferrite percentage is below 20 percent. According to Table 2, CASS Thermal Aging Susceptibility Screening Criteria, contained in the May 19, 2000, NRC letter from Christopher Grimes to Douglas J. Walters, materials that have a low molybdenum content and less than 20 percent delta ferrite are not susceptible to thermal aging for statically or centrifugally cast components. The NRC letter from Christopher Grimes to Carl Terry, dated June 5, 2001, states, "It is important to note that thermal and/or neutron embrittlement of CASS components becomes a concern only if cracks are present in the components, and that cracking has not been observed in CASS jet pump assembly components." Section 2.4 of the same letter states, "Further, the BWRVIP and the NRC's

Office of Nuclear Regulatory Research (RES) is engaged in a joint confirmatory research program to determine the effects of high levels of neutron fluence on BWR internals." The applicant has stated in its LRA that for open issues between the BWRVIP and NRC, the applicant will work as part of the BWRVIP to resolve these issues generically. When resolved, the applicant will follow the BWRVIP recommendations resulting from that resolution. The BWR RVIs program requires inspections of several jet pump assembly welds which are more susceptible to cracking than the CASS components and will serve as an indication of the potential need for more extensive inspections later in life.

Similar to the CASS jet pump components, the orificed fuel supports (OFS) are also manufactured to ASTM A351, grade CF8. These castings are low molybdenum and the maximum calculated delta ferrite percentage is below 20 percent. For reasons similar to those as discussed for the jet pump CASS components, the applicant concluded that no program is needed to manage the effects of thermal/neutron embrittlement of the CASS OFS.

The staff concurred with the applicant's response regarding the implementation of the industry-recommended monitoring program of the effects of high levels of neutron fluence on the CASS components. The staff concluded that the applicant's justification for excluding the CASS jet pumps and OFS components from the AMR for the extended period of operation is acceptable provided that ASME Code Section XI Subsections IWB, IWC, and IWD Program and the BWR Vessel Internals Program and inspection requirements of BWRVIP-41 are fully implemented for these components. The staff concurred with the applicant's statement that continued implementation of these AMPs and the technical guidelines of the BWRVIP-41 report provide reasonable assurance that the aging effects are adequately managed in the RV CASS jet pumps and OFS components. The staff found this response acceptable, and its concern related to RAI 3.1.2.2-9 is resolved.

3.1.2.3.18 Loss of Material Due to Galvanic, General, Crevice, and Pitting Corrosion

In LRA Table 3.1.2.2, the applicant addressed loss of material due to galvanic, general, crevice, and pitting corrosion in (1) RVIs core shroud and core plate, (2) RVIs core spray piping and spargers, (3) RVIs control rod housing and dry tubes and guide tubes, (4) RVIs jet pump assemblies, and (5) RVIs top guide.

The applicant also identified the implementation of relevant AMPs to manage the aging effects due to galvanic, general, crevice, and pitting corrosion of stainless steel and nickel-alloy materials when these materials are exposed to the BWR treated-water environment. In LRA Table 3.1.2.2, the applicant included AMP requirements that are specified in GALL Report, Volume 2, Table IV.B1 for each of the aforementioned components. However, GALL Report, Volume 2, Table IV.B1, does not identify loss of material due to crevice, general, and pitting corrosion as aging effects in stainless steel and nickel-alloy materials that are used in the aforementioned RV components when these components are exposed to the BWR treated-water environment. The staff's evaluation of the AMR related to these aging effects is discussed below.

In LRA Table 3.1.2.2, the applicant stated that the aging effects due to galvanic, general, crevice, and pitting corrosion of stainless steel and nickel-alloy materials in the RVIs will be managed by the Boiling Water Reactor Vessel Internals Program, Chemistry Control Program, and the inspection guidelines that are provided in the following BWRVIP reports for the applicable internal components:

BWRVIP-18 - "Boiling Water Reactor Core Spray Internal Inspection and Flaw Evaluation Guidelines."

BWRVIP-25 - "Boiling Water Reactor Core Plate Inspection and Flaw Evaluation Guidelines."

BWRVIP-26 - "Boiling Water Reactor Top Guide Inspection and Flaw Evaluation Guidelines."

BWRVIP-41 - "Boiling Water Reactor Jet Pump Assembly Inspection and Flaw Evaluation Guidelines."

BWRVIP–47 - "Boiling Water Reactor Lower Plenum Inspection and Flaw Evaluation Guidelines."

BWRVIP-76 - "Boiling Water Reactor Core Shroud Inspection and Flaw Evaluation Guidelines" – Staff review is not complete.

The implementation of these additional guidelines and AMPs is consistent with GALL AMP XI.M9. The applicant stated that continued implementation of these AMPs provides reasonable assurance that the aforementioned aging effects are adequately managed in the RVIs. The staff concluded that the implementation of the Chemistry Control Program will provide adequate controls on BWR reactor water chemistry, which in turn controls general, pitting and crevice corrosion in RVIs. Furthermore, inspection guidelines that are specified in the aforementioned staff-approved (with the exception of BWRVIP-76) BWRVIP reports will provide adequate guidance in performing the necessary inspections so that these aging effects in RVIs are properly identified in a timely manner.

In LRA Table 3.1.2.1, the applicant addressed loss of material due to galvanic, general, crevice, and pitting corrosion in (1) reactor head closure studs, (2) RV attachment welds, (3) RV heads, flanges and shells, (4) RV nozzles, (5) RV nozzles and safe ends, (6) RV penetrations, and (7) bolting in RV vents, drains, and the recirculation system.

The applicant also identified the implementation of relevant AMPs to manage the aging effects due to galvanic, general, crevice, and pitting corrosion of carbon and low-alloy steels, stainless steel and nickel-alloy materials when these materials are exposed to the BWR treated-water environment. In LRA Table 3.1.2.1, the applicant identified these aging effects and the relevant AMPs that are associated with each of the aforementioned components. In LRA Table 3.1.2.1, the applicant also included references related to GALL Report, Volume 2, Table IV.A1 for each of the aforementioned components.

GALL Report, Volume 2, Table IV.A1, does not identify loss of material due to crevice, general, and pitting corrosion as aging effects in carbon and low-alloy steel, stainless steel and nickel-alloy materials that are used in the aforementioned RV components when these components are exposed to the BWR treated-water environment. General, pitting, and crevice corrosion may occur in stainless steel or nickel-alloy components under exposure to aggressive, oxidizing environments. Normally, the presence of elevated dissolved oxygen and/or aggressive ionic impurity concentrations is necessary to create these oxidizing environments in the RCS.

The applicant stated that the Chemistry Control Program will be used at BFN. The Chemistry Control Program is based on EPRI Report TR-103515-R2 (the 2000 revision of "BWR Water Chemistry Guidelines"). The staff found EPRI TR-103515-R2 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience confirms the effectiveness of the Chemistry Control Program. In addition, this program provides an acceptable basis for minimizing the dissolved oxygen and ionic impurity concentrations that could otherwise, if left present in high concentrations, lead to an aggressive oxidizing RCS coolant environment, which can enhance corrosion of the RV components. Since the applicant has conservatively assumed that loss of material due to general corrosion, pitting corrosion, or crevice corrosion is an applicable aging effect for these RV components, the staff concludes that the Chemistry Control Program provides a sufficient mitigative strategy for managing this aging effect relative to the recommendations of the GALL Report. The applicant stated that it will invoke ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, which is an established AMP. This program has appropriate requirements for inspecting the aforementioned vessel components.

The staff concluded that by implementing the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and Chemistry Control Program, the applicant demonstrated that the effects of aging due to general, pitting, and crevice corrosion 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 found that the applicant had demonstrated that the effects of aging will be adequately managed 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, the staff found that the applicant appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant 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).

3.1.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging of the reactor vessel internals and reactor coolant system components that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the reactor vessel, internals, and reactor coolant system, as required by 10 CFR 54.21(d).

3.2 <u>Aging Management of Engineered Safety Features</u>

This section of the SER documents the staff's review of the applicant's AMR results for the ESF systems components and component groups associated with the following systems:

- containment
- standby gas treatment
- high pressure coolant injection
- residual heat removal
- core spray
- containment inerting
- containment atmosphere dilution

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant provided AMR results for components. In LRA Table 3.2.1, "Summary of Aging Management Evaluations for Engineered Safety Features Evaluated in Chapter V of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the ESF systems components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the ESF systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit, during the weeks of June 21 and July 2, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs are consistent with 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 had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.2.2.2, dated

July 2001. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.3. The staff's evaluation of its technical review is also documented in Section SER 3.2.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the ESF systems components.

Table 3.2-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.2 that are addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings and valves in emergency core cooling system (Item Number 3.2.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Piping, fittings, pumps and valves in emergency core cooling system (Item Number 3.2.1.2)	Loss of material due to general corrosion	Water Chemistry Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL which recommends further evaluation (See Section 3.2.2.2.2)
Components in containment spray (PWR only), standby gas treatment system (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1.3)	Loss of material due to general corrosion	Plant-specific	One-Time Inspection Program; Chemistry Control Program; Systems Monitoring Program	See Section 3.2.2.2.2

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Containment isolation valves and associated piping (Item Number 3.2.1.6)	Loss of material due to microbiologically influenced corrosion (MIC)	Plant-specific	Open-Cycle Cooling Water Program	See Section 3.2.2.2.4
Seals in standby gas treatment system (Item Number 3.2.1.7)	Changes in properties due to elastomer degradation	Plant-specific	N/A	See Section 3.2.2.2.5
Drywell and suppression chamber spray system nozzles and flow orifices (Item Number 3.2.1.9)	Plugging of nozzles and flow orifices by general corrosion products	Plant-specific	N/A	See Section 3.2.2.2.7
External surface of carbon steel components (Item Number 3.2.1.10)	Loss of material due to general corrosion	Plant-specific	One-Time Inspection Program; Chemistry Control Program; Systems Monitoring Program	See Section 3.2.2.2.2
Piping and fittings of CASS in emergency core cooling systems (Item Number 3.2.1.11)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS Program	N/A	Not Applicable BFN does not require a thermal aging embrittlement of CASS AMP
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 Program	Open-Cycle Cooling Water System Program	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 Program	Closed-Cycle Cooling Water System Program	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
Emergency core cooling system valves and lines to and from high pressure coolant injection and reactor core isolation cooling pump turbines (Item Number 3.2.1.14)	Wall-thinning due to flow-accelerated corrosion	Flow Accelerated Corrosion Program	Flow Accelerated Corrosion Program	Consistent with GALL which recommends no further evaluation (See Section 3.2.2.1)
Pumps, valves, piping and fittings in emergency core cooling system (Item Number 3.2.1.16)	Crack initiation and growth due to SCC and IGSCC	Water Chemistry Program; BWR Stress Corrosion Cracking Program	Chemistry Control Program; BWR Stress Corrosion Cracking Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.2.2.1))
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 Program	Bolting Integrity Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.2.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.2.2.1, 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 SER Section 3.2.2.2, 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 SER Section 3.2.2.3, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.2.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the ESF systems components:

- Bolting Integrity Program
- Buried Piping and Tanks Inspection Program
- Chemistry Control Program
- One-Time Inspection Program

- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program
- Systems Monitoring Program
- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Corrosion Program

Staff Evaluation. In LRA Tables 3.2.2-1 through 3.2.2-7, the applicant provided a summary of AMRs for the ESF systems components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report which the applicant stated are consistent 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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 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 had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but that 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 was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in its BFN audit and review 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 had identified the appropriate GALL AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff reviewed the LRA to confirm that the applicant (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the ESF system components that are subject to an AMR.

The staff identified that LRA Table 3.2.2.5 is not consistent with the GALL Report Item IVC1.3-c. The staff asked the applicant to explain this inconsistency. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the correct AMPs for LRA Table 3.2.2.5 are the Chemistry Control Program and the BWR Stress Corrosion Cracking Program (instead of the One-Time Inspection Program). The staff found this acceptable because it is consistent with the GALL Report.

On the basis of its audit, the staff determined that for AMRs not requiring further evaluation, as identified in LRA Table 3.2.1 (Table 1), the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated 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 concluded 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 concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application. In LRA Section 3.2.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the 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 (MIC)
- changes in properties due to elastomer degradation
- local loss of material due to erosion
- buildup of deposits due to corrosion
- quality assurance for aging management of NSR components

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 audited and reviewed the applicant’s evaluation to determine whether it had adequately addressed the issues that had been further evaluated. In addition, the staff reviewed the applicant’s further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. Details of the staff’s audit are documented in the staff’s audit and review report. The staff’s evaluation of the aging effects is discussed in the following sections.

For some line items in LRA Tables 3.2.2.1 through 3.2.2.7 that are identified to be consistent with the GALL Report, the applicant cross-referenced specific line items in LRA Tables 3.1.1 and 3.2.1, for which the GALL Report recommends further evaluation. Where the GALL Report recommends further evaluation, the staff reviewed the applicable further evaluations provided in LRA Sections 3.1.2.2 and 3.2.2.2 against the criteria provided in SRP-LR Sections 3.1.2.2 and 3.2.2.2, respectively.

The following subsections provide the staff's assessment of the applicant's further evaluations in LRA Section 3.2.2.2 against the criteria provided in SRP-LR Section 3.2.2.2.

The staff's assessment of the applicant's further evaluations in LRA Section 3.1.2.2 is provided in SER Section 3.1.2. Where credited, the assessment also considered applicability to aging management of the ESF systems.

3.2.2.2.1 Cumulative Fatigue Damage

Consistent with the SRP-LR, the applicant references LRA Section 4.3.3. Cumulative fatigue damage is a TLAA, and is evaluated in SER Section 4.

3.2.2.2.2 Loss of Material Due to General Corrosion (LRA Section 3.2.2.2.2)

The applicant references LRA Table 3.2.1, items 3.2.1.3 and 3.2.1.10, to address loss of material due to general corrosion for ESF components in containment isolation, standby gas treatment, residual heat removal and containment inerting systems and also for RCS components. These Table 1 items reference LRA Section 3.2.2.2.2 for further evaluation. The staff reviewed LRA Section 3.2.2.2.2 against the criteria in SRP-LR Section 3.2.2.2.2.

In LRA Section 3.2.2.2.2, the applicant addressed loss of material due to general corrosion of the portions of ESF systems piping filled with treated water or air/gas, and the external surfaces of carbon steel components.

SRP-LR Section 3.2.2.2.2 states that the management of loss of material due to general corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling systems [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be further evaluated. The existing AMP relies on monitoring and control of primary water chemistry to mitigate degradation; however, control of primary water chemistry does not preclude loss of material due to general corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation. Also, the GALL Report recommends further evaluation on a plant-specific basis to ensure that the aging effect on the external surfaces of BWR carbon steel components is adequately managed.

In the LRA Section 3.2.2.2.2, the applicant stated that loss of material due to general corrosion of the portions of ESF systems filled with treated water is managed by the Chemistry Control Program and the One-Time Inspection Program. The One-Time Inspection Program is used to verify the effectiveness of the Chemistry Control Program for managing the loss of material due to general corrosion. Loss of material due to general corrosion of the air/gas portions of these systems is managed by the One-Time Inspection Program for internal surfaces.

General corrosion of all external surfaces of carbon steel components is managed by the plant-specific Systems Monitoring Program. The staff reviewed the BFN procedure (NEDP-20, rev. 3, "Conduct of the Engineering Organization," September 9, 2002) for conducting system monitoring during system walkdowns. The walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of carbon steel components.

On the basis of its review of the Chemistry Control Program, One-Time Inspection Program, and the Systems Monitoring Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to general corrosion, consistent with the recommendations in the GALL Report.

3.2.2.2.3 Local Loss of Material due to Pitting and Crevice Corrosion

The applicant references LRA Table 3.2.1, item 3.2.1.5, to address loss of material due to pitting and crevice corrosion for ESF components in containment and containment inerting systems and also for RCS components. The applicant's further evaluation is in LRA Section 3.2.2.2.3. The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

In the LRA Section 3.2.2.2.3, the applicant addressed local loss of material from pitting and crevice corrosion that could occur in the ESF systems and associated piping filled with treated water or air/gas.

SRP-LR Section 3.2.2.2.3 states that the management of local loss of material due to pitting and crevice corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling system piping and fittings [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be evaluated further. The existing AMP relies on monitoring and control of primary water chemistry to mitigate degradation. However, control of coolant water chemistry does not preclude loss of material due to crevice and pitting corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage the loss of material due to pitting and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

In the LRA Section 3.2.2.2.3, the applicant stated that loss of material due to pitting and crevice corrosion of the portions of ESF systems filled with treated water is managed by the Chemistry Control Program and the One-Time Inspection Program. The One-Time Inspection Program is used to verify the effectiveness of the Chemistry Control Program for managing the loss of material due to pitting and crevice corrosion. Loss of material due to pitting and crevice corrosion of the air/gas portions of these systems is managed by the One-Time Inspection Program for internal surfaces.

On the basis of its review of the Chemistry Control Program and One-Time Inspection Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to pitting and crevice corrosion, consistent with the recommendations in the GALL Report.

3.2.2.2.4 Local Loss of Material due to Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4. The applicant references LRA Table 3.2.1, item 3.2.1.6, to address loss of material due to MIC for ESF components in containment and containment inerting systems.

SRP-LR Section 3.2.2.2.4 states that 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 that the aging effect is adequately managed.

LRA Section 3.2.2.2.4 states that the applicant considers MIC to be an aging mechanism for systems in a raw water environment. BFN has no systems containing raw water that penetrate primary containment. Several raw water systems penetrate secondary containment. BFN utilizes the Open-Cycle Cooling Water Program to manage the aging effects that could be caused by MIC in these systems.

On the basis of its review of the Open-Cycle Cooling Water Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to MIC, consistent with the recommendations in the GALL Report.

3.2.2.2.5 Changes in Properties due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5. In LRA Section 3.2.2.2.5, the applicant described its AMR for change in material properties due to elastomer degradation, for seals in ductwork and filters associated with the standby gas treatment (SGT) system. The applicant stated that the normal operating temperature of the SGT system is less than the defined limits for hardening and loss of strength of installed elastomers. This statement is not consistent with the criteria in SRP-LR Section 3.2.2.2.5.

LRA Table 3.2.2.2, which includes the AMR results for elastomer seals in the SGT system, does not reference LRA Table 1, Item 3.2.1.7. Instead, the applicant identified the AMR for these components to be not consistent with the GALL Report, and concluded that aging management is not required. The staff evaluation of the applicant's AMR results for elastomers in the SGT system was not conducted during the onsite audit.

3.2.2.2.6 Local Loss of Material due to Erosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.2.2.2.7 Buildup of Deposits due to Corrosion

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7. In LRA Section 3.2.2.2.7, the applicant addressed the plugging of components due to general corrosion that could occur in the spray nozzles and flow orifices of the drywell and suppression chamber spray system. The applicant stated that spray nozzles are brass and are not susceptible to general corrosion, and that there are no orifices susceptible to general corrosion that are occasionally wetted in the ESF systems.

The applicant does not reference LRA Table 1, Item 3.2.1.9 in any of the AMR tables for the ESF systems. The applicant concluded that, since the spray nozzles and orifices are not susceptible to general corrosion that may cause plugging, aging management is not required. The staff found the applicant's AMR results to be acceptable, on the basis that the subject components are not susceptible to general corrosion.

3.2.2.2.8 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

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 (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant 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).

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.2.2.1 through 3.2.2.7, 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, or that are not addressed in the GALL Report.

In LRA Tables 3.2.2.1 through 3.2.2.7, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item 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 the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

The staff requested the applicant to provide additional information on the issues described in the following general RAIs. These RAIs, the applicant's responses, and the staff's evaluation of the responses are described below.

In RAI 3.2-1, dated November 18, 2004, the staff stated that in LRA Tables 3.2.2.1 through 3.2.2.7, carbon and low-alloy steel bolting in an inside air (external) or outside air (external) environment is not identified with any AERMs. The applicant indicated that this is because BFN does not use high yield strength bolting. Therefore, the staff requested that the applicant discuss the specific material grade used for the bolting in each of the associated systems, and justify the basis for concluding that crack initiation/growth due to SCC is not a concern for the bolting during the period of extended operation.

In its letter dated December 16, 2004, the applicant responded as follows:

> The identified aging management program is the Bolting Integrity Program. As noted, a cracking aging effect is not identified because high yield bolting materials (yield strength above 150 ksi) were not identified and plant operating experience does not indicate an adverse history of bolt cracking. Stress corrosion cracking (SCC) of bolted closures and fasteners is a condition of high yield strength bolting material where a fastener that is statically loaded well below its yield strength can experience sudden failure. SCC occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. SCC of high yield strength bolted closures in BWRs requires a corrosive environment typically attributed to leakage of pressure boundary joints or exposure to wetted ambient environments (indoor, outdoor, buried and submerged) and the use of thread lubricant containing MoS_2 (molybdenum disulfide).
>
> The use of MoS_2 thread lubricant is not allowed by site and engineering procedures. Therefore, any maintenance on this mechanical equipment would result in the use of non-MoS_2 thread lubricant. Loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and no aging management is required for the period of extended operation.

The staff concluded that loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and that aging management is not required for these components for the period of extended operation. On the basis of the applicant's response, the staff's concern described in RAI 3.2-1 is resolved.

In RAI 3.2-2, dated November 18, 2004, the staff stated that in LRA Tables 3.2.2.1 through 3.2.2.4, 3.2.2.6, and 3.2.2.7, nickel-alloy bolting in inside air (external) environments were not identified with any AERMs. The applicant invoked industry guidance/experience to support the analysis. Therefore, the staff requested the applicant to provide a detailed discussion of the air environment involved, and to justify the basis for concluding that there are no AERMs under such material/environment combinations. The staff also requested information on the stated industry guidance.

In its letter dated December 16, 2004, the applicant responded as follows:

> The nickel-alloy bolting in the Containment Isolation System was evaluated for wear and no applicable wear mechanism was identified for non-RCPB components. Therefore, wear is not an aging mechanism that requires management for the period of extended operation for the Containment Isolation System. Nickel-alloy bolting, similar to stainless steel bolting, is subject to cracking under severe environmental conditions such as high temperature and being buried or submerged (potentially, depending on type of external water). Nickel-alloy bolting in the Containment Isolation System is not subject to this severe environment; therefore, cracking was not identified.

> The copper-alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation or periodic wetting could occur. The identified aging effects were then determined based on the particular copper alloy present and whether condensation or periodic wetting could occur. Based on this evaluation, there were no instances where copper alloys components with > 15% Zn were subjected to an aggressive environment or condensation/periodic wetting. Therefore, no aging effects that require management during the period of extended operation were identified for the copper alloy components in the subject tables. A summary description of the industry guidance (i.e., when industry guidance is referenced was provided in the EPRI Technical Report 1003056, “Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools”) for copper alloys.

The applicant response dated December 16, 2004, contains detailed information for copper alloys. On the basis of the applicant's response, the staff’s concern described in RAI 3.2-2 is resolved.

In RAI 3.2-3, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.1, material carbon and low-alloy steel, component type valves in a treated water (internal) environment are not identified with any AERMs. The staff noted that the component, material and environment combination for this component is similar to that identified in the GALL Report, Item V.C.1-a, which recommends a plant-specific AMP to be evaluated for the identified aging effects. Therefore, the staff requested that the applicant explain why the aging effects identified in the GALL Report, such as loss of material due to general, pitting, and crevice corrosion, are not applicable to these components.

In its response, by letter dated December 16, 2004, the applicant stated that the reason for the line entries that indicate no aging effects is an attempt to ensure completeness of GALL Report comparison. For carbon and low-alloy steel valves in a treated water environment, rows 78, 79, and 80 of LRA Table 3.2.2.1 address the applicable aging mechanisms. The applicable GALL Volume 2 line item was determined to be V.C.1-a. which lists five aging effects: general, pitting, crevice, MIC, and biofouling. For a treated water environment, the BFN AMR determined that microbiologically influenced corrosion and biofouling did not require management for the period of extended operation. However, the BFN AMR determined that in addition to the aging mechanisms identified in the GALL Report, galvanic corrosion was also applicable. This was documented in the AMR as:

Galvanic corrosion – Yes, with notes H and 3
General corrosion – Yes, consistent with GALL
Pitting corrosion – Yes, consistent with GALL
Crevice corrosion – Yes, consistent with GALL
Microbiologically influenced corrosion – No, see below
Biofouling – No, see below

The first aging mechanism is documented in row 78 with notes H and 3. The next three aging mechanisms, which are consistent with the GALL Report, form the basis for row 80 of LRA Table 3.2.2.1. The last two aging mechanisms are documented in row 79 of LRA Table 3.2.2.1 with a note 5 was incorrect which should be 4. Note 4, stated that based on system design and operating history, MIC and biofouling were determined to be not applicable to the treated water portions of this system.

The staff found the above applicant's response to have adequately clarified the fact that loss of material due to general, pitting, and crevice (in addition to galvanic) corrosion has indeed been identified in its AMR. Therefore, the staff's concern described in RAI 3.2-3 is resolved.

In RAI 3.2-3, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.3, the applicant did not identify elastomer flexible connectors in an air/gas (internal) environment with any AERMs. The applicant stated that there are no applicable aging effects for this material/environment combination and believes that this is consistent with industry guidance. Therefore, the staff requested additional information to justify the basis for concluding that there are no AERMs under such material/environment combinations, including an insight into the industry guidance.

In its response, by letter dated December 16, 2004, the applicant stated that the issue involved aging effects due to material property changes and cracking of the rubber fabric reinforced (elastomer) flexible connectors upstream and downstream of the gland seal condenser blower (gland exhauster) in an air/gas environment. These effects are caused by exposure to ultraviolet radiation, oxygen, ozone, heat, and radiation. The applicant stated that the elastomer degradation due to these aging mechanisms are not significant because the ultraviolet radiation and ozone effects to the internal surfaces of the components are negligible. The LRA does identify elastomer degradation due to ultraviolet radiation and ozone for the external surfaces of these components.

The applicant further stated that maximum temperature rating for rubber is 130 °F per industry guidance. During normal operation, the temperature of the flexible connectors is significantly less than 130 °F; therefore, degradation from thermal exposure is not identified as an aging mechanism requiring management for the period of extended operation. The applicant further stated that the dose threshold for radiation degradation of rubber is 10^7 rads. The ionizing radiation the flexible connectors will receive is negligible (much less than 10^7 rads); therefore, degradation from ionizing radiation is not identified as an aging mechanism requiring management for the period of extended operation.

The staff found the applicant's basis for not identifying any aging effects for the elastomer flexible connectors to be acceptable. Therefore, the staff's concern described in RAI 3.2-4 is resolved.

In RAI 3.2-5, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.5, the applicant stated that aluminum-alloy fittings in a treated water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Therefore, the staff requested additional information to explain why loss of material due to general and galvanic corrosion is not identified as a potential AERM during the period of extended operation. The applicant was also requested to explain how the Chemistry Control Program, in association with the One-Time Inspection Program, is used to manage the identified aging effects.

In its response, by letter dated December 16, 2004, the applicant stated that, per industry guidance, aluminum and aluminum-based alloys in a treated water environment are not susceptible to loss of material due to general corrosion. In addition, the applicant stated that the aluminum fittings in Table 3.2.2.5 are the flanges off the 24-inch diameter condensate supply header within the core spray system. An electrically insulating rubber gasket is used to electrically separate the aluminum flanges from more cathodic materials, such as copper or stainless or carbon steels. Based on that, the staff concurred with the applicant's conclusion that galvanic corrosion is not a concern for this configuration for aluminum fittings in a treated water environment for the core spray system.

The applicant also stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The staff accepted the Chemistry Control Program for primary systems program and its evaluation of this program is documented in SER Section 3.0.3.2.2. GALL AMP XI.M32, “One-Time Inspection,” is used to verify the Chemistry Control Program's effectiveness, as recommended by the GALL Report. The staff considered that the applicant had adequately addressed its concerns stated in the RAI; therefore, RAI 3.2-5 is resolved.

In RAI 3.2-6, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.5 polymer tubing in an air/gas (internal) or inside air (external) environment is not identified with any AERMs. Therefore, the staff requested the applicant to provide a discussion of the air environment involved, and justify the basis for concluding that there are no AERMs under such material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that polymer tubing in the core spray system is the Tygon (polyvinyl chloride) tube off the closed drain valve downstream of the drain dirt separator (trap) used in the keep fill system (shown on drawing 2-47E814-1). Under normal operating conditions, the internal and external environment is atmospheric air. The applicant stated that unlike metals, thermoplastics do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. Therefore, acceptability for the use of thermoplastics in an air/gas environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects.

The applicant stated that the temperature and radiation damage threshold limits are 200°F and 2×10^7 rads, respectively. Neither of these limits is challenged in the LRA where Tygon is utilized; however, Tygon may be degraded when exposed to air and ultraviolet radiation; therefore, the applicant stated that for the external surface of the Tygon tubing, degradation should have been identified in the LRA by revising the line item to include "Hardening and loss of strength due to polymer degradation (ultraviolet radiation)" as an aging effect and an aging mechanism. The Systems Monitoring Program will be used to manage the aging effect.

Based on the above, the staff considered that the applicant had adequately addressed its concerns; therefore, RAI 3.2-6 is resolved.

3.2.2.3.1 Containment System – Summary of Aging Management Evaluation – Table 3.2.2.1

The staff reviewed LRA Table 3.2.2.1, which summarizes the results of AMR evaluations for the containment system component groups.

In LRA Table 3.2.2.1, the applicant identified no aging effects in containment system component groups made of aluminum alloys exposed to inside/outside air in the ductwork and heat exchangers or carrying air/gas in the ductwork; carbon and low-alloy steel piping/fittings embedded or encased in concrete; copper-alloy piping carrying air/gas; glass (fittings) exposed to air/gas, treated water, or inside air; and nickel-alloy fittings, stainless steel fittings, and zinc-alloy ductwork exposed to air/gas. These environment's conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion of low-alloy steel requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.1, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel, nickel alloys and stainless steel piping and fittings in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Table 3.2.2.1, heat exchanger components made of carbon/low-alloy steel and exposed to raw water are susceptible to loss of material due to biofouling, MIC, crevice, galvanic, general, and pitting corrosion; and heat exchanger components made of copper alloys and exposed to raw water are susceptible to fouling due to biological particulate build-up and loss of material due to selective leaching, biofouling, MIC, crevice and pitting corrosion. The applicant credited the Selective Leaching of Materials Program and Open-Cycle Cooling Water System Program to manage these aging effects. The latter AMP, in accordance with the guidelines of GL 89-13, includes managing aging effects by condition monitoring (system and component testing, visual inspections, and NDE testing), and by preventive actions (biocide treatment and filtering to prevent loss of material due to MIC and biofouling and flow blockage and reduction of heat transfer due to biological and particulate fouling). The staff found this acceptable.

Aluminum-alloy heat exchangers carrying air/gas; carbon/low-alloy steel piping/fittings and heat exchangers exposed to air/gas; and copper-alloy components of heat exchangers exposed to air/gas are susceptible to loss of material due to general pitting, crevice corrosion, and fouling due to particulate build-up. In LRA Table 3.2.2.1, the applicant credited the One-Time

Inspection Program to manage these aging effects. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

In LRA Table 3.2.2.1, piping and fittings made of carbon/low-alloy steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. This AMP involves preventive measures to mitigate corrosion (external coatings and wrappings have been applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, “Maintenance Rule Program.” The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, signs of environmental degradation, signs of leakage, and appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.2 Standby Gas Treatment System – Summary of Aging Management Evaluation – Table 3.2.2.2

The staff reviewed LRA Table 3.2.2.2, which summarizes the results of AMR evaluations for the standby gas treatment system component groups.

In LRA Table 3.2.2.2, the applicant identified no aging effects in standby gas treatment system component groups made of aluminum-alloy ductwork, copper-alloy tubing, stainless steel fittings, and zinc-alloy ductwork. All of these components carry air/gas and their external surface is exposed to inside air. These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion of low-alloy steel requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.2, piping and fittings made of carbon/low-alloy steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. This AMP involves preventive measures to mitigate corrosion (external coatings and wrappings have been applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, "Maintenance Rule Program." The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, signs of environmental degradation, signs of leakage, and appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

Carbon and low-alloy steel and cast iron/cast iron alloy piping, fittings, and valves exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.2, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

Carbon and low-alloy steel and cast iron/cast iron alloy piping, fittings, and valves external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.3 High Pressure Coolant Injection System – Summary of Aging Management Evaluation – Table 3.2.2.3

The staff reviewed LRA Table 3.2.2.3, which summarizes the results of AMR evaluations for the high pressure coolant injection (HPCI) system component groups.

In LRA Table 3.2.2.3, the applicant identified no aging effects in HPCI system component groups made (1) out of carbon and low-alloy steel piping and fittings exposed to inside air (external surface) and carrying lube oil, cast iron alloy pumps and valves carrying lube oil; (2) copper-alloy tubing/fittings carrying air/gas and lube oil; (3) glass (fittings) exposed to air/gas and lube oil; and (4) nickel-alloy flexible connectors and stainless steel fittings exposed to inside air (external). These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.3, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel piping, fittings, and various components, cast iron and cast iron alloy pumps, copper-alloy condensers and heat exchangers, nickel-alloy flexible connectors, and stainless steel piping, fittings, tubing, and valves in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component’s intended function will be maintained during the period of extended operation.

In components made from cast iron and cast iron alloys and copper alloy, selective leaching takes place when these components are exposed to corrosion-inhibited treated water, oxygenated and de-oxygenated treated water. In LRA Table 3.2.2.3, the applicant identified Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron pumps and copper-alloy condensers exposed to treated water. The applicant’s selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Cast iron/cast iron alloy fittings and carbon and low-alloy steel external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. Elastomer flexible connections exposed to inside air are subject to elastomer degradation due to ultraviolet radiation, which is also managed by the Systems Monitoring Program. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.4 Residual Heat Removal System – Summary of Aging Management Evaluation – Table 3.2.2.4

The staff reviewed LRA Table 3.2.2.4, which summarizes the results of AMR evaluations for the residual heat removal (RHR) system component groups.

In LRA Table 3.2.2.4, the applicant identified no aging effects in RHR system component groups made of aluminum exposed to inside air (external), carbon and low-alloy steel piping/fittings exposed to inside air (external), and copper-alloy and stainless steel fittings carrying air/gas. These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.4, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel heat exchangers, piping, fittings, and other components, cast iron alloy pumps, copper-alloy, and aluminum alloy fitting, and stainless steel piping, fittings, and other components in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component’s intended function will be maintained during the period of extended operation.

In components made from cast iron and copper alloy, selective leaching takes place when these components are exposed to raw water, corrosion-inhibited treated water, oxygenated and de-oxygenated treated water, or are buried underground. In LRA Table 3.2.2.4, the applicant identified the Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron heat exchangers and pumps and copper-alloy fittings exposed to raw water or treated water. The applicant’s selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Carbon and low-alloy steel components and cast iron/cast iron alloy heat exchangers and pumps’ external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

In LRA Table 3.2.2.4, heat exchanger components made of carbon/low-alloy steel, cast iron alloys and stainless steel exposed to raw water are susceptible to loss of material due to biofouling, MIC, crevice, galvanic, general, and pitting corrosion as well as fouling product buildup due to biological. The applicant credited the Open-Cycle Cooling Water System Program to manage this aging effect. This AMP, in accordance with the guidelines of GL 89-13, includes managing aging effects by condition monitoring (system and component testing, visual inspections, and NDE testing), and by preventive actions (biocide treatment and filtering to prevent loss of material due to MIC, biofouling, flow blockage and reduction of heat transfer due to biological and particulate fouling). The staff found this acceptable.

Carbon and low-alloy steel and cast iron/cast iron alloy fittings exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.4, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.5 Core Spray System – Summary of Aging Management Evaluation – Table 3.2.2.5

The staff reviewed LRA Table 3.2.2.5, which summarizes the results of AMR evaluations for the core spray system component groups.

In LRA Table 3.2.2.5, the applicant identified no aging effects in core spray system component groups made of aluminum exposed to inside air (external); carbon and low-alloy steel piping/fittings exposed to inside air (external); and stainless steel fittings carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.5, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel heat exchangers, piping, fittings, and various other components, cast iron alloy pumps, and stainless steel piping, fittings, and valves in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion; therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component's intended function will be maintained during the period of extended operation.

In components made from cast iron alloys, selective leaching takes place when these components are exposed to corrosion-inhibited treated water, oxygenated and de-oxygenated treated water. In LRA Table 3.2.2.5, the applicant identified Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron heat exchangers and pumps exposed to treated water. The applicant's selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Carbon/low-alloy steel components and cast iron/cast iron alloy pumps external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

Carbon/low-alloy steel and cast iron/cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.5, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.6 Containment Inerting System – Summary of Aging Management Evaluation – Table 3.2.2.6

The staff reviewed LRA Table 3.2.2.6, which summarizes the results of AMR evaluations for the containment inerting system component groups.

In LRA Table 3.2.2.6, the applicant identified no aging effects in containment inerting system component groups made of aluminum, carbon and low-alloy steel, copper alloys, nickel alloys, and stainless steel carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group; therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

Carbon/low-alloy steel and cast iron/cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.6, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Repot for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3.7 Containment Atmosphere Dilution System – Summary of Aging Management Evaluation – Table 3.2.2.7

The staff reviewed LRA Table 3.2.2.7, which summarizes the results of AMR evaluations for the containment atmosphere dilution system component groups.

In LRA Table 3.2.2.7, the applicant identified no aging effects in containment inerting system component groups made of aluminum, cast iron alloys, copper alloys, and stainless steel carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group; therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

Carbon/low-alloy steel and cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.7, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

Carbon/low-alloy steel and cast iron alloy components' external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

In LRA Table 3.2.2.7, piping and fittings made of stainless steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion as well as cracking due to SCC. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. During the GALL consistency audit the staff requested the applicant to describe how this AMP would detect cracking in buried piping, if this is an applicable aging effect. By letter dated October 8, 2004, the applicant submitted its formal response to the staff's audit question, stating that, in Table 3.2.2.7, line items 12 and 22 identify cracking for buried stainless steel piping and fittings and should be deleted. This line's temperature is less than 140°F and, therefore, is not subject to stress corrosion cracking. This is the only place in the LRA where the buried tank and piping inspection program was credited for detecting cracking. Therefore, the buried tank and piping inspection program does not detect cracking. The staff found the above explanation acceptable.

The buried tank and piping inspection AMP involves preventive measures to mitigate corrosion (external coatings and wrappings applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, "Maintenance Rule Program." The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, environmental degradation, leakage, and for appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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>. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant 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).

3.2.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging for the of the ESF systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the ESF systems, as required by 10 CFR 54.21(d).

3.3 <u>Aging Management of Auxiliary Systems</u>

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:

- auxiliary boiler
- fuel oil
- residual heat removal service water
- raw cooling water
- raw service water
- high pressure fire protection
- potable water
- ventilation
- heating, ventilation, and air conditioning (HVAC)
- control air
- service air
- CO_2
- station drainage
- sampling and water quality
- building heat
- raw water chemical treatment
- demineralizer backwash air
- standby liquid control
- off-gas
- emergency equipment cooling water
- reactor water cleanup
- reactor building closed cooling water
- reactor core isolation cooling
- auxiliary decay heat removal
- radioactive waste treatment
- fuel pool cooling and cleanup
- fuel handling and storage
- diesel generator
- control rod drive (CRD)
- diesel generator starting air
- radiation monitoring
- neutron monitoring
- traversing in-core probe
- cranes

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant provided AMR results for components. In LRA Table 3.3.1, "Summary of Aging Management Evaluations for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the auxiliary systems components and component groups.

The applicant’s AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant’s review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit, during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant’s claim that certain identified AMRs are consistent with 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 had identified the appropriate GALL AMRs. The staff’s evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff’s audit evaluation are documented in the audit and review report and are summarized in SER Section 3.3.2.1.

In the onsite audit, the staff also included those selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant’s further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.3.2.2. The staff’s audit evaluations are documented in the audit and review report and are summarized in SER Section 3.3.2.2.

During the staff’s onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff’s audit evaluations are documented in the audit and review report and are summarized in SER Section 3.3.2.3. The staff’s evaluation of its technical review is also documented in SER Section 3.3.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems components.

Table 3.3-1 below provides a summary of the staff’s evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.3, that are addressed in the GALL Report.

Table 3.3-1 Staff Evaluation 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	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.1)
Linings in spent fuel pool 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	Systems Monitoring Program	(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 54.21(c)	TLAA	This TLAA is evaluated in Section 4.7, Other Plant-Specific Analyses, and in Section 4.3, Metal Fatigue BFN does not have a chemical and volume control system or a shutdown cooling system
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	Chemistry Control Program; One-Time Inspection Program	(See Section 3.3.2.2.4)
Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components (Item Number 3.3.1.5)	Loss of material due to general, pitting, and crevice corrosion; MIC	Plant-specific	Chemistry Control Program; One-Time Inspection Program	(See Section 3.3.2.2.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in reactor coolant pump oil collect system of fire protection (Item Number 3.3.1.6)	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-Time Inspection	N/A	Not applicable BFN does not have an oil collection system for its reactor recirculation pumps
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system (Item Number 3.3.1.7)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel Oil Chemistry Program; One-Time Inspection Program	Fuel Oil Chemistry Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.7)
Piping, pump casing, and valve body and bonnets in shutdown cooling system (older BWR) (Item Number 3.3.1.8)	Loss of material due to pitting and crevice corrosion	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Not applicable BFN is not an older BWR with a shutdown cooling system The shutdown cooling system is performed by the RHR system (See Section 3.3.2.3.3)
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	Chemistry Control Program	(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 Program	Structures Monitoring Program	Consistent with GALL, which recommend no further evaluation (See Section 3.3.2.1)
Neutron absorbing sheets in spent fuel storage racks (Item Number 3.3.1.12)	Reduction of neutron absorbing capacity due to Boraflex degradation	Boraflex Monitoring Program	N/A	Not applicable BFN uses Boral as the spent fuel storage rack neutron absorber
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 stress corrosion cracking	Chemistry Control Program	Chemistry Control Program	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
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; MIC	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System	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	Overhead Heavy Load and Light Load Handling Systems	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 biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Buried piping and fittings (Item Number 3.3.1.18)	Loss of material due to general, pitting, and crevice corrosion; MIC	Buried Piping and Tanks Surveillance Program; Buried Piping and Tanks Inspection Program	Buried Piping and Tanks Inspection Program	(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 Program	Compressed Air Monitoring Program	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 protections (Item Number 3.3.1.20)	Loss of material due to wear; hardening and shrinkage due to weathering	Fire Protection Program	Fire Protection Program	Consistent with GALL, with exceptions, 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	Fire Water System	Consistent with GALL, which recommends no further evalation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in diesel fire system (Item Number 3.3.1.22)	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire Protection Program; Fuel Oil Chemistry Program	Fire Protection Program; Fuel Oil Chemistry Program	Consistent with GALL, with exceptions, 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	Above Ground Carbon Steel Tanks Program	Above Ground Carbon Steel Tanks Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)
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 Program	Bolting Integrity Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)
Components in contact with sodium pentaborate solution in standby liquid control system (BWR) (Item Number 3.3.1.25)	Crack initiation and growth due to SCC	Chemistry Control Program	Chemistry Control Program	Consistent with GALL, with exceptions, which recommend no further evaluation (See Section 3.3.2.1)
Components in reactor water cleanup system (Item Number 3.3.1.26)	Crack initiation and growth due to SCC and IGSCC	Reactor Water Cleanup System Inspection Program	BWR Reactor Water Cleanup System Program	The NUREG-1801 XI.M25 Reactor Water Cleanup system AMP provides criteria for which inspections are not recommended. Since BFN meets these criteria, inspections will not be conducted (See Section 3.0.3.2.15)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in shutdown cooling system (older BWR) (Item Number 3.3.1.27)	Crack initiation and growth due to SCC	BWR Stress Corrosion Cracking Program; Chemistry Control Program	N/A	Not applicable BFN is not an older BWR with a shutdown cooling system. The shutdown cooling function is performed by the RHR system (See Section 3.3.2.3.3)
Components in shutdown cooling system (older BWR) (Item Number 3.3.1.28)	Loss of material due to pitting and crevice corrosion, and MIC	Closed-Cycle Cooling Water System	N/A	Not applicable BFN is not an older BWR with a shutdown cooling system. The shutdown cooling function is performed by the RHR system (See Section 3.3.2.3.3)
Components (aluminum, bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink	Loss of material due to selective leaching	Selective Leaching of Materials Program	Selective Leaching of Materials Program	Consistent with GALL, which recommend no further evaluation (See Section 3.3.2.1)
Fire barriers, walls, ceilings, and floors in fire protection	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire Protection System; Structures Monitoring System	Fire Protection System; Structures Monitoring System	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.3.2.1, 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 SER Section 3.3.2.2, 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 SER Section 3.3.2.3, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of

AMPs that are credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.3.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the auxiliary systems components:

- Bolting Integrity Program (B.2.1.16)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)
- Buried Piping and Tanks Inspection Program (B.2.1.25)
- Fuel Oil Chemistry Program (B.2.1.27)
- Chemistry Control Program (B.2.1.5)
- Open-Cycle Cooling Water System Program (B.2.1.17)
- Closed-Cycle Cooling Water System Program (B.2.1.18)
- Fire Water System Program (B.2.1.24)
- Fire Protection Program (B.2.1.23)
- Compressed Air Monitoring Program (B.2.1.21)
- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- BWR Reactor Water Cleanup System Program (B.2.1.22)
- Flow-accelerated Corrosion Program (B.2.1.15)
- Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.1.20)
- Diesel Starting Air Program (B.2.1.41)

Staff Evaluation. In LRA Tables 3.3.2-1 through 3.3.2-34, the applicant provided a summary of 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 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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 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 had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated 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 was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review 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 had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review 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 had identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant had (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report, and (3) identified those aging effects for the auxiliary systems components that are subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated 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 concluded that the AMR results that the applicant claimed to be consistent with the GALL Report are, in fact, consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.3.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the 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
- quality assurance for aging management of non-safety-related components
- cracking 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 claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant’s further evaluations against the criteria in SRP-LR Section 3.3.2.2. Details of the staff’s audit are documented in the staff’s BFN audit and review report. The staff’s evaluation of the aging effects is discussed in the following sections.

3.3.2.2.1 Loss of Material due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR 3.3.2.2.1.

In LRA Section 3.3.2.2.1, the applicant addressed the further evaluation of programs to manage loss of material in components of the spent fuel pool cooling and cleanup system.

SRP-LR Section 3.3.2.2.1 states that loss of material due to general, pitting, and crevice corrosion could occur in the channel head and access cover, tubes, and tubesheets of the heat exchanger in the spent fuel pool cooling and cleanup system. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry to manage the effects of loss of material from general, pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. No loss of material aging effects are observed for stainless steel components exposed to air.

Further, SRP-LR Section 3.3.2.2.1 states that loss of material due to pitting and crevice corrosion could occur in the filter housing, valve bodies, and nozzles of the ion exchanger in the spent fuel pool cooling and cleanup system. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry to manage the effects of loss of material from pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause pitting, or crevice corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

The applicant stated that the portion of the fuel pool cooling and cleanup (FPC) system that contains components requiring an AMR includes the water filled piping within the reactor building, and the applicant credited the Chemistry Control Program and One-Time Inspection Program to manage loss of material. The Chemistry Control Program is credited with managing loss of material for stainless steel components in this portion of the spent fuel pool cooling and cleanup system that are exposed to treated water. The One-Time Inspection Program, which addresses the verification program recommendation in the GALL Report, provides for the inspection of systems to verify that AMPs are effective and that aging effects are not occurring. This is consistent with the GALL Report and acceptable to the staff.

3.3.2.2.2 Hardening and Cracking or Loss of Strength due to Elastomer Degradation or Loss of Material due to Wear

The staff reviewed LRA Section 3.3.2.2.2 against the criteria in SRP-LR 3.3.2.2.2.

In LRA Section 3.3.2.2.2, the applicant addressed the further evaluation of programs to manage the potential for degradation of elastomers in collars and seals in spent fuel cooling systems and ventilation systems.

SRP-LR Section 3.3.2.2.2 states that hardening and cracking due to elastomer degradation could occur in elastomer linings of the filter, valve, and ion exchangers in spent fuel pool 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 that these aging effects are adequately managed.

In LRA Section 3.3.2.2.2, the applicant stated that elastomers are not used in components subject to an AMR in the spent fuel cooling and cleanup system. The applicant also stated that for the ventilation systems, hardening and loss of strength due to elastomer degradation is dependent on environmental conditions. The applicant also stated that loss of material due to wear of elastomer components is managed by the systems monitoring program if the environmental threshold is exceeded. The staff found this acceptable.

The staff noted that LRA Table 3.3.2.28 identifies elastomer degradation due to thermal exposure as an AERM for flexible connectors in the diesel generator ventilation system having an internal environment of air/gas. The applicant credited the One-Time Inspection Program to manage this aging effect and claimed consistency with GALL Report, Item VII.F4.1-b, referencing Table 3.2.1, Item 3.3.1.2. However, Table 3.2.1, Item 3.3.1.2 refers to the further evaluation in LRA Section 3.3.2.2.2, which states that the Systems Monitoring Program will be used to manage hardening and loss of strength of elastomers in ventilation systems. The staff during the onsite audit requested the applicant to explain why the One-Time Inspection Program was credited for managing elastomer aging for flexible connectors in the diesel generator ventilation system. In its formal response, by letter dated October 8, 2004, the applicant stated that the One-Time Inspection Program is credited for the inspection of elastomers where the degradation mechanism may be internal. The Systems Monitoring Program is credited for the inspection of elastomers where the degradation mechanism may be external. The applicant stated that LRA Section 3.3.2.2.2 should include a discussion of the One-Time Inspection Program for internal surfaces of elastomers. If degradation is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program. The staff found this acceptable.

3.3.2.2.3 Cumulative Fatigue Damage

In LRA Section 3.3.2.2.3, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4 documents the staff's review of the applicant's evaluation of this TLAA.

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 3.3.2.2.4.

In LRA Section 3.3.2.2.4, the applicant addressed the further evaluation of programs to manage the potential for cracking in the regenerative and non-regenerative heat exchanger components in the reactor water cleanup system.

SRP-LR Section 3.3.2.2.4 addresses crack initiation and growth due to SCC in the regenerative and non-regenerative heat exchanger components in the reactor water cleanup system. The GALL Report recommends further evaluation to ensure that these aging effects are managed adequately.

The applicant stated that it uses the Chemistry Control Program and the One-Time Inspection Program to manage cracking and SCC of these stainless steel components. In the ESF section of the GALL Report, Volume 2, Item V.D2.1-c, the management of stainless steel components performing a pressure boundary function is addressed by using the Chemistry Control Program. Therefore, the applicant's use of the Chemistry Control Program to manage crack initiation and growth due to SCC is consistent with the GALL Report and, therefore, is acceptable to the staff.

3.3.2.2.5 Loss of Material due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.5 against the criteria in SRP-LR 3.3.2.2.5.

In LRA Section 3.3.2.2.5, the applicant addressed the further evaluation of programs to manage 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.

SRP-LR Section 3.3.2.2.5 states that 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; the auxiliary and radwaste area; the primary containment heating and ventilation systems; the piping of the diesel generator building ventilation system; the above ground 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, crevice, and MIC could occur in the duct fittings, access doors, and closure bolts, equipment frames and housing of the duct. Loss of materials due to pitting and crevice corrosion could occur in the heating/cooling coils of the air handler heating/cooling. 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 212°F in the ventilation systems. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant credited the One-Time Inspection Program for managing loss of material due to corrosion of carbon and low-alloy steel, cast iron/cast iron alloy, and copper alloy components in the off-gas, heating, ventilation, and air conditioning, diesel generator, reactor core isolation cooling, raw cooling water, diesel generator starting air, ventilation, standby liquid control, and demineralizer backwash air systems with internal surfaces exposed to air/gas. The staff found this acceptable.

The applicant credited the Systems Monitoring Program for managing loss of material due to corrosion of carbon and low-alloy steel components in the auxiliary boiler, fuel oil, RHRSW, raw cooling water, raw service water, high pressure fire protection, potable water ventilation, HVAC, control air, service air, CO_2, station drainage, sampling and water quality, building heat, raw water chemical treatment, demineralizer backwash air, standby liquid control, off-gas, emergency equipment cooling water, reactor water cleanup, reactor building closed cooling water, reactor core isolation cooling, radioactive waste treatment, fuel pool cooling and cleanup, diesel generator, CRD, diesel generator starting air, and radiation monitoring systems with external surfaces exposed to air. The staff found this acceptable.

The applicant credited the Diesel Starting Air Program for managing loss of material due to corrosion of carbon and low-alloy steel components in the diesel generator starting air system with internal surfaces exposed to air/gas. The staff found this acceptable.

The staff noted that LRA Table 3.3.2.28 identifies loss of material due to crevice, general, and pitting corrosion as an AERM for carbon and low-alloy steel components in a treated water environment. LRA Table 3.2.1, Item 3.3.1.5 is referenced and consistency with the GALL Report is noted. The Closed-Cycle Cooling Water Program is credited for managing this aging effect. However, LRA Table 3.2.1, Item 3.3.1.5 references the further evaluation in 3.3.2.2.5, which pertains to components in an air environment, and does not include the Closed-Cycle Cooling Water Program as one of the programs to manage aging. The staff inquired as to why LRA Table 3.2.1, Item 3.3.1.5 was referenced for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.3.2.28 for the diesel generator system has six line items with a treated water environment that match the GALL Report. The correct GALL Report, Volume 1, Table 1 reference for the items that match the GALL Report is Item 3.3.1.15. Five of the LRA Table 3.3.2.28 treated water line items correctly reference 3.3.1.15; one incorrectly references 3.3.1.5. The reference to 3.3.1.5 should be 3.3.1.15. The staff reviewed this response and concluded that it is acceptable.

3.3.2.2.6 Loss of Material due to General, Galvanic, Pitting, and Crevice Corrosion

In LRA Section 3.3.2.2, the applicant addressed the further evaluation of programs to manage loss of material in the reactor coolant pump oil collection system to verify the effectiveness of the Fire Protection Program. The applicant stated that this aging effect is not applicable to BFN since the BFN design does not include a recirculation pump oil collection system. The staff concluded that this is acceptable since the BFN design does not include a reactor coolant pump oil collection system.

3.3.2.2.7 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Biofouling

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR 3.3.2.2.7.

In LRA Section 3.3.2.2.7, the applicant addressed the further evaluation of programs to manage loss of material in the diesel fuel oil system to verify the effectiveness of the diesel fuel monitoring program.

SRP-LR Section 3.3.2.2.7 states that loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling could occur in the internal surface of tanks in the diesel fuel oil system and due to general, pitting, and crevice corrosion and MIC 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 control of fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709 and D2276 to manage loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion/biofouling to verify the effectiveness of the program. 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's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.7, the applicant stated that it uses the Fuel Oil Chemistry Program to manage loss of material for the diesel fuel oil system. In addition, the applicant will use the One-Time Inspection Program to verify the effectiveness of the fuel oil chemistry program. The inspection will ensure that corrosion is not occurring at locations where contaminants accumulate. The One-Time Inspection Program addresses the one-time inspection recommendation in the GALL Report.

The staff reviewed the Fuel Oil Chemistry Program and found that the program will adequately manage the effects of aging so that the intended functions will be maintained. The staff also reviewed the One-Time Inspection Program, which will be used to verify the effectiveness of the Fuel Oil Chemistry Program.

3.3.2.2.8 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program.

3.3.2.2.9 Cracking Initiation and Growth due to Stress Corrosion Cracking and Cyclic Loading

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.3.2.2.10 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR 3.3.2.2.10.

In LRA Section 3.3.2.2.10, the applicant addressed the further evaluation of programs to manage 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.

SRP-LR Section 3.3.2.2.10 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 stated that boral is used as a neutron absorbing material in the spent fuel pools. Reduction of neutron absorbing capacity and loss of material due to general corrosion could occur in the boral neutron absorbing material in spent fuel storage racks. The Chemistry Control Program manages general corrosion. An inspection of boral coupon test specimens was performed that confirmed no significant aging degradation had occurred and the neutron absorbing capability of the boral had not been reduced. Reduction of neutron absorbing capacity and loss of material due to general corrosion will be managed by the Chemistry Control Program.

The staff reviewed the Chemistry Control Program and found that the program will adequately manage the effects of aging so that the intended functions will be maintained.

3.3.2.2.11 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.11 against the criteria in SRP-LR 3.3.2.2.11.

In LRA Section 3.3.2.2.11, the applicant addressed the further evaluation of programs to manage the potential for loss of material in buried piping of the service water and diesel fuel oil systems.

SRP-LR Section 3.3.2.2.11 states that loss of material due to general, pitting, and crevice corrosion and MIC could occur in the underground piping and fittings in the OCCW 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 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, ensuring that loss of material is not occurring.

The applicant credited the Buried Piping and Tanks Inspection Program for managing loss of material for buried components of the service water and diesel fuel oil systems. This is consistent with GALL AMP XI.M34, “Buried Piping Inspection.” The staff reviewed the applicant's operating history and found that the frequency of pipe excavation was sufficient to manage the effects of loss of material. The staff reviewed the Buried Piping Inspection Program and concluded that it is acceptable.

3.3.2.2.12 Evaluation of Auxiliary Systems AMRs That Reference Further Evaluations Not Included Under Auxiliary Sysyems

In the AMR for components in the auxiliary systems, the applicant referenced several further evaluations that are included under systems other than the auxiliary systems. These further evaluations were referenced based on applicability to the material, environment, and aging effect identified for components in the auxiliary systems. The staff reviewed these further evaluations for applicability to the auxiliary systems; the assessment is documented in the following subsections.

Crack Initiation and Growth due to SCC, IGSCC, and Thermal and Mechanical Loading. In LRA Section 3.1.2.2.4, the applicant addressed the further evaluation of programs to manage crack initiation and growth due to thermal and mechanical loading or stress corrosion cracking of components in the reactor coolant system. This aging effect is referenced in LRA Table 3.2.1, Item 3.1.1.7, which the applicant referenced in the auxiliary systems AMRs for components in the sampling and water quality, standby liquid control, reactor water cleanup, reactor core isolation cooling, and neutron monitoring systems.

The staff noted that the LRA identifies crack initiation/growth due to cyclic loading as an AERM for various mechanical components in the sampling and water quality, standby liquid control, reactor water cleanup, reactor core isolation cooling, and neutron monitoring systems. The ASME ISI Program and One-Time Inspection Program are credited to manage this aging effect. The staff noted similar entries in the AMRs for the ESF systems and the reactor coolant system. The staff inquired as to why the Chemistry Control Program had been not included to manage this aging effect for these components since the Chemistry Control Program is included in the further evaluation in LRA Section 3.1.2.2.4. The applicant's response and the staff's evaluation are addressed in SER Section 3.1.2.2.4.

Loss of Material due to General Corrosion. In LRA Section 3.2.2.2.2, the applicant addressed the further evaluation of programs to manage loss of material due to general corrosion for components in the ESF systems. This aging effect is referenced in LRA Table 3.2.1, Items 3.2.1.2, 3.2.1.3, and 3.2.1.10, which the applicant referenced in the auxiliary systems AMRs for components in the auxiliary boiler, raw service water, potable water, service air, station drainage, sampling and water quality, building heat, demineralizer backwash air, off-gas, reactor core isolation cooling, radioactive waste treatment, CRD, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.2.

The staff noted that the LRA identifies loss of material due to general, crevice, and pitting corrosion as an AERM for mechanical components in a treated water environment in the radioactive waste treatment system (LRA Table 3.3.2.25). LRA Table 3.2.1, Items 3.2.1.3 and 3.2.1.5 are referenced and consistency with the GALL Report is noted. The One-Time Inspection Program is credited for managing this aging effect; however, the further evaluation in the LRA Section 3.2.2.2.2 identifies the Chemistry Control Program for managing the effects of corrosion for components in a treated water environment. During the onsite audit, the staff inquired as to the technical basis for using the One-Time Inspection Program alone to manage aging due to corrosion for components in a treated water environment, instead of the Chemistry Control program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the treated water in the radioactive waste treatment system is waste that was generated from systems that contain chemistry control treated water; however, once this water becomes a waste steam, the chemistry can no longer be controlled. Since the portions of the system exposed to treated water have their water source from chemistry control systems, the potential for corrosion is low. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff reviewed the applicant's response and concluded that it is acceptable since the water in the radioactive waste treatment system is waste that was generated from systems that contain chemistry control treated water. Once the treated water becomes a waste stream the chemistry can no longer be controlled, which is why the Chemistry Control Program is not credited for this aging effect. The potential for corrosion is low for these components and the One-Time Inspection Program will be performed to verify that corrosion is not occurring.

The staff noted that LRA Tables 3.3.2.3, 3.3.2.5, 3.3.2.14, 3.3.2.21, and 3.3.2.25 identify loss of material due to biofouling, MIC, crevice corrosion, general corrosion, and pitting corrosion as an AERM for stainless steel components in a raw water environment. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5, and 3.2.1.6 are referenced and consistency with the GALL Report is noted. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5 and 3.2.1.6 reference further evaluations in LRA Sections 3.2.2.2.2. 3.2.2.2.3, and 3.2.2.2.4, respectively. However, LRA Sections 3.2.2.2.2 and 3.2.2.2.3 pertain to components in treated water, for which the Chemistry Control and One-Time Inspection Programs are identified to manage this aging effect. Only LRA Section 3.2.2.2.4 pertains to components in raw water. The staff asked why LRA Table 3.2.1, Items 3.2.1.3 and 3.2.1.5 are referenced for these components. The staff also inquired as to the technical basis for using the One-Time Inspection Program to manage aging due to MIC for the components in Table 3.3.2.25 instead of the Open-Cycle Cooling Water Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Sections 3.2.2.2.2 and 3.2.2.2.3 only address treated water environments and should include a discussion of the Open-Cycle Cooling Water Program for raw water systems.

The staff found this acceptable, because the applicant indicated that LRA Sections 3.2.2.2.2 and 3.2.2.2.3 should also include raw water environments and credited the Open-Cycle Cooling Water Program for raw water systems. With these additions, the applicant's AMR results will be consistent with the GALL Report.

<u>Loss of Material due to Pitting and Crevice Corrosion</u>. In LRA Section 3.2.2.2.3, the applicant addressed the further evaluation of programs to manage the loss of material due to pitting and crevice corrosion for components in the engineered safety feature systems. This aging effect is referenced in LRA Table 3.2.1, Items 3.2.1.4 and 3.2.1.5, which the applicant referenced in the auxiliary systems AMRs for components in the raw service water, sampling and water quality, building heat, reactor core isolation cooling, auxiliary decay heat removal, radioactive waste treatment, CRD, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.3.

The staff noted that the LRA identified loss of material due to crevice and pitting corrosion as an AERM for mechanical components in a treated water environment in the radiation monitoring system (LRA Table 3.3.2.31). The applicant referenced LRA Table 3.2.1, Item 3.2.1.5 and consistency with the GALL Report is noted. The Closed-Cycle Cooling Water Program is credited for managing this aging effect. However, the further evaluation in LRA Section 3.2.2.2.3 identifies the Chemistry Control Program and One-Time Inspection Program for managing the effects of corrosion for components in a treated water environment. The staff inquired as to the technical basis for using the Closed-Cycle Cooling Water Program alone to manage aging due to corrosion for components in a treated water environment instead of the Chemistry Control Program and One-Time Inspection Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Closed-Cycle Cooling Water Program is consistent with the related GALL Report Closed-Cycle Cooling Water Program (XI.M21). The Closed-Cycle Cooling Water Program provides for prevention and detection of aging effects in plant closed cycle cooling water systems. LRA Section 3.2.2.2.3 only addresses treated water environments and should include a discussion of the Closed-Cycle Cooling Water Program for treated water in closed cooling loops.

The staff found this acceptable because the applicant indicated that LRA Section 3.2.2.2.3 should also include treated water in closed cooling loops and credit the Closed-Cycle Cooling Water Program.

<u>Local Loss of Material due to Microbiologically Influenced Corrosion</u>. In LRA Section 3.2.2.2.4, the applicant addressed the further evaluation of programs to manage the local loss of material due to MIC for components in the engineered safety feature systems. This aging effect is referenced in LRA Table 3.2.1, Item 3.2.1.6, which the applicant referenced in the auxiliary systems AMRs for components in the raw service water, sampling and water quality, radioactive waste treatment, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.2.4.

The staff noted that LRA Table 3.3.2.25 identifies loss of material due to MIC as an AERM for components in a raw water environment in the radioactive waste treatment system. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5, and 3.2.1.6, are referenced, and consistency with the GALL Report is noted. The One-Time Inspection Program is credited to manage this aging effect. However, Section 3.2.1.6 references the further evaluation in LRA Section 3.2.2.2.4, which identifies the Open-Cycle Cooling Water Program for managing MIC. The staff inquired as to the technical basis for crediting the One-Time Inspection Program for managing aging due to MIC for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water environment identified in the radioactive waste treatment system is waste that was generated from floor and equipment drain sumps and may contain dirty or contaminated water. This waste stream is not subject to the Chemistry Control Program or the Open-Cycle Cooling Water Program. The potential for corrosion in this system would be lower than actual "raw water" systems because a portion of the waste stream would be treated water from chemistry control systems. The applicant determined that inspection in accordance with the One-Time Inspection Program will verify integrity of this system during the period of extended operation. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff reviewed the applicant's response and concluded that it is acceptable since the raw water environment identified in the radioactive waste treatment system is waste that was generated from floor and equipment drain sumps and may contain dirty or contaminated water. The potential for corrosion in this system would be lower than actual raw water systems because a portion of the waste stream would be treated water from chemistry control systems. The One-Time Inspection Program will verify integrity of this system during the period of extended operation.

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 (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had 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).

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.3.2.1 through 3.3.2.34, 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, or that are not addressed in the GALL Report.

In LRA Tables 3.3.2.1 through 3.3.2.34, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combination that are not evaluated in the GALL Report, the staff reviewed the applicant’s evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff’s evaluation is discussed in the following sections.

During its review, the staff determined that similar AMR line items required clarification for several systems. In several of the auxiliary systems, the LRA states that copper alloy components in an inside air (external) environment experience no AERMs. However, the existence of AERMs depends on the particular alloy and whether there is condensation or pooling on the component. For example, high zinc (>15 percent) alloys in condensation or pooling water may exhibit stress corrosion cracking, selective leaching, or pitting and crevice corrosion. The LRA definition of inside air (external) would support condensation and pooling.

In RAI 3.3.2.1-1, dated October 12, 2004, the staff requested the applicant to clarify how condensation and pooling were considered in the evaluation of potential aging of susceptible alloys. In its response, by letter November 3, 2004, the applicant stated that the copper alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation could occur (i.e., components containing fluid at a temperature below the dew point of the external environment). The aging effects evaluation then determined the aging effects/mechanisms based on the particular alloys are susceptible and whether condensation or periodic wetting occurred. The applicant provided its guidelines for assessing the particular alloys.

The staff reviewed the applicant's criteria for determining aging effects based on the particular copper alloy and found them acceptable and consistent with industry guidance. The applicant evaluated the components individually and applied acceptable criteria for determining the AERMs of the alloys exposed to condensation or pooling. Therefore, the staff found the applicant's evaluation of copper alloys in inside air to be acceptable.

<u>Aging Management of Bolting in Auxiliary Systems Bolting</u>. The staff reviewed LRA Tables 3.3.2.1 through 34, which relates to the AMR evaluations for bolting in auxiliary systems bolting. The staff was concerned that cracking and loss of preload are not identified as aging effects for bolting managed by the Bolting Integrity Program, including bolting subject to high pressure, high temperature or vibration. The Bolting Integrity Program should provide for bolting preload control for all bolting within scope of license renewal.

The LRA AMR tables credit the Bolting Integrity Program for managing loss of bolting function due to various corrosion mechanisms in auxiliary systems bolting. Loss of preload and cracking are not identified as aging effects for bolting in the AMR tables for auxiliary systems.

GALL AMP XI.M18 specifically credits the Bolting Integrity Program developed and implemented in accordance with commitments made in response to communications on bolting events to provide an effective means of ensuring bolting reliability. The program relies on industry recommendations for a comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting. The program covers all bolting within the scope of license renewal. The GALL Report includes loss of material, cracking and loss of preload as aging effects. Bolting preload control, as delineated in EPRI NP-5769 with exceptions noted in NUREG-1339, is applied to manage loss of preload. NUREG CR-6679 also identifies loss of preload as an aging effect and the draft GALL Report update 2005 includes loss of preload as an aging effect for bolting in ESF, auxiliary and S&PC systems. Further, SRP-LR Section A.1.2.1 states, "However leakage from bolted connections should not be considered abnormal events. Although bolting connections are not supposed to leak, experience has shown that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal."

The Bolting Integrity Program is identified as an existing program that takes exceptions to GALL AMP XI.M18 evaluation elements. The exceptions affect element 1 - scope of the program and possibly element 4 - detection of aging effects. It appears that Element 4 - detection of aging effects - is identified as being affected by the exceptions. The applicant credits ASME Code

Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program for ASME Section XI inspections of Class 1 and Class 2 bolting.

For auxiliary system closure bolting, the staff is concerned that cracking and loss of preload are not entirely addressed by either the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program or Bolting Integrity Program. Although ASME Section XI requires bolt torquing loads to be in accordance with ASME Section III for replacement of Class 1 and 2 bolting, no bolt torquing requirements are specified for Class 3 bolting, NSR bolting or bolting that is reused after being removed for maintenance. ASME Section XI does address examination of Class 1 bolting, but no examination is required for Class 2 bolting smaller than 2 inch and Class 3 bolting regardless of size or NSR bolting. ASME Section XI does provide for inspection during leakage testing, but this inspection may not necessarily detect loss of preload or flange leakage at other times. GALL AMP XI.M18, “Bolting Integrity,” does manage cracking and loss of preload in all closure bolting within scope of license renewal. As identified in EPRI NP-5769, preload reduction is caused by a number of factors, including stress relaxation (both at room temperature and elevated temperature), thermal cycling (particularly for gaskets), creep and flow of gasket material during initial compression, vibration and shock, and elastic interactions between separately-tightened bolts. The GALL Report includes high pressure and high temperature systems as being susceptible to crack initiation. Therefore, the applicant should clarify if the bolting integrity AMP is consistent with GALL AMP XI.M18 in regard to managing cracking and loss of preload or explain how these aging effects are managed by other programs or maintenance practices.

By letter dated October 8, 2004, the applicant provided additional information in response to Audit Inspection Question 310 on bolting activities. The applicant stated that, "Structural bolting procurement activities, receipt inspection and installation (torquing), as defined in TVA procedure General Engineering Specification (GES) G-29B-S01, P.S.4.M.4.4, ASME Section III and Non-Section III (including American Institute of Steel Construction (AISC), ANSI B31.1, and ANSI B31.5) bolting material, are considered part of the Bolting Integrity Program and meet the industry recommendations for these activities as delineated in NUREG-1339 and EPRI NP-5769.

By letter dated March 16, 2005, the applicant responded to the clarification request on bolting. For valve closure bolting not within the RCPB, the applicant clarified that stress relaxation is a thermal effect that results in loss of preload. The applicant explained that stress relaxation is a design driven effect that would be detected and corrected early and is not considered an applicable aging effect in non-RCPB valve closure bolting. The applicant stated that installation procedures are in place that specify proper bolting installation practices and bolt torque values. In this letter, the applicant also clarified that non-RCPB bolting is not susceptible to SCC as the yield strength is less than 150 ksi. Further, the applicant explained that crack initiation and growth due to cyclic loading is not considered a license renewal concern due to high cycle fatigue, since it would be discovered and corrected during the current licensing period.

The staff reviewed the applicant's response and agreed that loss of preload in auxiliary system closure bolting should be managed by proper bolting installation practices and torque values supplemented by inspections. The staff also concurred that proper bolting practices and the selection of bolting less than 150 ksi should result in auxiliary system closure bolting not being susceptible to SCC.

However, the staff did not agree that cracking and loss of preload are not aging effects for license renewal, unless the applicant demonstrates that these potential adverse effects will be corrected prior to the period of extended operation. LRA Section B.2.1.16 states that the BWR fleet of plants, including BFN, has experienced bolting degradation issues. Plant-specific and industry operating experience should be reviewed to determine if the applicant's bolting practices are effective in precluding loss of preload and cracking for all auxiliary system closure bolting within the scope of license renewal. For example, despite implementation of bolting practices, recent industry operating experience such as LER 2005-01 for Fermi 2 demonstrates the importance of sufficient bolt torque to prevent major gasket leakage in BWR auxiliary systems such as reactor building closed cooling water (RBCCW). The applicant was requested to review operating experience and submit the results of any self assessments, inspections or maintenance activities to determine if closure bolting in auxiliary systems will be effectively managed for cracking and loss of preload. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the component intended function(s) will be maintained during the period of extended operation. If by a review of operating experience the applicant cannot demonstrate that effective bolting practices are in place to manage cracking and loss of preload in auxiliary system closure bolting, the applicant should commit to a Bolting Integrity Program consistent with the GALL Report or explain how these aging effects are managed by other programs or maintenance practices.

By letter dated June 3, 2005, the applicant provided additional information concerning cracking and loss of preload in auxiliary systems bolting. In this response the applicant included information relevant to their review of operating experience with bolting.

Cracking - The applicant clarified that high yield strength heat-treated alloy steel bolting materials are not specified for flanged connections at BFN. The applicant also clarified that the use of MoS_2 thread lubricant is not allowed by site and engineering procedures. Further the applicant clarified that a review of the operating experience had not identified any instances where mechanical component failure was attributable to stress corrosion cracking of high strength pressure boundary bolting. Thus, the applicant concluded that the aging effect loss of bolting function was not identified at BFN because both the susceptible material and corrosive environment portions of the stress corrosion crack mechanism are not present.

Loss of Preload - The applicant clarified that loss of preload due to stress relaxation (creep) is not an aging effect for standard grade B7 carbon steel bolting used in auxiliary system bolting with temperatures less than 700 °F. The applicant also clarified that BFN has taken actions to address NUREG-1339, "Resolution to Generic Safety Issue 29; Bolting Degradation or Failure in Nuclear Power Plants." These actions include the implementation of good bolting practices in accordance with those referenced in EPRI NP-5769, with the exceptions noted in NUREG-1339, and EPRI TR-104213 to address the potential for joint failure such that it is not a concern for the current or extended operating term. The applicant identified that a review of the BFN operating experience did not identify any instances where the mechanical component failure was attributable to loss of pressure boundary bolting preload. In regard to recent industry experience with joint failures associated with loss of preload identified in Fermi 2 LER 2005-01, the applicant attributed this failure to inadequate gasket compression due to a number of factors including insufficient initial bolt torque. The applicant characterizes this failure as indicative of a design/maintenance problem rather than an aging concern.

The staff reviewed the applicant's response dated March 16, 2005, and found the response to be reasonable and acceptable. The applicant provided additional information to clarify that cracking and loss of preload in bolting are being effectively managed. However, the response did not provide the results of any self assessments, inspections or maintenance activities, and operating experience to determine if closure bolting in auxiliary systems was effectively managed at BFN for cracking and loss of preload. The staff discussed this issue with the applicant in a teleconference, and the verification of this confirmatory item was addressed during the AMP inspection performed on September 2005. The applicant also agreed to include this in the Appendix A Commitment Table. In the inspection report, a letter dated November 8, 2005, the staff concluded that the bolting practices in BFN are functioning adequately. The staff, therefore, concluded that there is reasonable assurance that aging effects, including cracking and loss of preload, for bolting used in auxiliary systems are being and will continue to be effectively managed during the period of extended operation.

No Aging Effect or Aging Management Program Identified. The staff reviewed LRA Tables 3.3.2.1 through 3.3.2.34, which summarized the results of AMR evaluations for the auxiliary systems component groups.

The applicant included entries in these tables for which there are no aging effects or AMPs identified. However, the material/environment combinations for these components do have aging effects identified in other table entries. For example, LRA Table 3.3.2.31, row 14 shows stainless steel fittings in treated water with no aging effect or AMP, while the next row has the same component/material/ environment with loss of material identified as an AERM. The staff inquired as to the purpose of the entries showing no aging effect or AMP. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the reason for the line entries that indicate no aging effects is an attempt to ensure completeness of the GALL Report comparison. For the example given, LRA Table 3.3.2.31, rows 14 and 15 address stainless steel fittings that form a portion of containment isolation. The applicable GALL Report, Volume 2 line item was determined to be V.C.1-b. GALL Report, Volume 2, Item V.C.1-b lists four aging effects; pitting and crevice corrosion; MIC; and biofouling. For a treated water line, the AMR determined that MIC and biofouling did not require management for the period of extended operation. This was documented in the AMR as:

- pitting corrosion – Yes
- crevice corrosion – Yes
- MIC – No
- biofouling – No

The first two aging mechanisms form the basis for LRA Table 3.3.2.31, row 15. The last two are documented in LRA Table 3.3.2.31, row 14 as no aging effect with Note 4 identified. Note 4 states, “Based on system design and operating history, MIC and biofouling are not applicable to the treated water portions of this system.” Also, Table 3.3.2.14, row 58 should refer to Notes I, 5, and Table 3.3.2.28; row 56 should refer to Notes I, 2.

The staff found that the applicant’s entries showing no aging effect or AMP are acceptable since they are included only to ensure completeness of the GALL Report comparison; and also concurred with the corrections identified for LRA Table 3.3.2.14, row 58 and LRA Table 3.3.2.28, row 56.

The staff reviewed LRA Tables 3.3.2.6, 3.3.2.9, 3.3.2.12, 3.3.2.14, 3.3.2.21, 3.3.2.22, 3.3.2.23, 3.3.2.28, 3.3.2.30, and 3.3.2.31, which summarize the results of AMR evaluations for the high pressure fire protection; heating, ventilation, and air conditioning; CO_2, sampling and water quality; reactor water cleanup; reactor building closed cooling water; reactor core isolation cooling; diesel generator; diesel generator starting air; and radiation monitoring systems component groups, respectively.

The applicant identified glass fittings in environments of air/gas, inside air, treated water, raw water, lubricating oil, and aqueous film-forming foam (AFFF) as having no aging effects requiring management. During the onsite audit, the staff inquired as to the specific applications of these glass fittings and the chemical properties of AFFF with regard to its reactivity with glass. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the following components, which contain glass, are included within the scope of license renewal for BFN:

- System 26, High Pressure Fire Protection - level gauge
- System 31, Heating, Ventilation, and Air Conditioning - level gauge
- System 37, Gland Seal Water - level gauge
- System 39, CO_2 - level gauge
- System 43, Sampling and Water Quality - level gauge
- System 64, Containment - level gauge
- System 68, Reactor Recirculation - sight glass
- System 70, Reactor Building Closed Cooling Water - level gauge
- System 82, Diesel Generator - level gauge
- System 86, Diesel Generator Starting Air - sight glass
- System 90, Radiation Monitoring - sight glass, moisture traps, and air filters

In addition, the applicant stated that AFFF contains the following:

- water
- 2-(2-butoxyethoxy) ethanol
- ethylene glycol
- alkyl polyglycoside
- fluoroalkyl surfactant

This mixture of hydrocarbons, surfactants, fluorosurfactants, and water is not reactive with glass.

The staff concluded that the applicant's determination of no aging effect for these glass components for the environments identified is acceptable since the environments identified are not reactive with glass.

3.3.2.3.1 Auxiliary Boiler System – Summary of Aging Management Evaluation – Table 3.3.2.1

The staff reviewed LRA Table 3.3.2.1, which summarizes the results of AMR evaluations for the auxiliary boiler system component groups.

In LRA Table 3.3.2.1, the applicant proposes that fittings, piping, and valves made from carbon and low-alloy steel in an environment of treated water (internal) and subjected to galvanic corrosion will be managed by the One-Time Inspection Program.

The staff reviewed the One-Time Inspection Program and its evaluation is documented in SER Section 3.0.3.1. Galvanic corrosion is typically minimized through standard design practices. Therefore, any galvanic corrosion is expected to be sufficiently slow that the One-Time Inspection Program is appropriate for this aging effect. If there is any significant galvanic corrosion, this AMP will identify the problem and initiate appropriate corrective action. Therefore, the staff found the use of the One-Time Inspection Program to be appropriate for this aging effect.

LRA Section 3.3.2.1, states that valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.1-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information provided, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the auxiliary boiler system.

<u>Loss of Material Due to Corrosion for Cast Iron and Carbon/Low Alloy Steels in an Air/Gas Environment</u> The applicant identified loss of material due to crevice, general, and pitting corrosion as an AERM for valves constructed of cast iron and cast iron alloy, as well as fittings, piping, traps, and valves constructed of carbon or low-alloy steel in a moist air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the air/gas components in the auxiliary boiler system were exposed to secondary quality water or steam that had been isolated by the layup of the auxiliary boilers. The portions of the system that now contain air/gas are isolated and there is no mechanism for introducing contaminants or additional oxygen. Since the portions of the auxiliary boiler system exposed to air/gas were originally chemistry controlled, the potential for corrosion is low. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable. The water to which these components were exposed was chemically treated, and the components are now isolated such that neither contaminants nor additional oxygen will be introduced into the air/gas environment. Therefore, the potential for corrosion of these components is low. The one-time inspection will verify that corrosion is not occurring. If corrosion is detected, additional inspections and corrective actions will be taken.

Loss of Material due to Selective Leaching of Copper Alloy in a Treated Water Environment. The applicant identified loss of material due to selective leaching for components constructed of copper alloy in a treated water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for this material and environment combination for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the One-Time Inspection Program had been identified in error. The correct AMP for this aging effect is the Selective Leaching of Materials Program.

The staff concluded that the applicant's response is acceptable since the Selective Leaching of Materials Program was developed specifically to address loss of material due to selective leaching. The One-Time Inspection Program was incorrectly listed in Table 3.2.2.1 for this component.

3.3.2.3.2 Fuel Oil System – Summary of Aging Management Evaluation – Table 3.3.2.2

The staff reviewed LRA Table 3.3.2.2, which summarizes the results of AMR evaluations for the fuel oil system component groups.

In LRA Table 3.3.2.2, the applicant states that pumps, piping, and fittings made from carbon and low-alloy steel in fuel oil experience no aging effects. Copper alloy in fuel oil is subjected to loss of material due to MIC. The applicant also states that fittings made from copper alloy in inside air experience no aging effects. For flexible hoses made from elastomer - rubber in fuel oil (internal) subjected to elastomer degradation due to oxidation, the applicant proposes that these be managed by the One-Time Inspection Program. Flexible hoses made from elastomer - rubber in inside air may experience elastomer degradation due to ultraviolet radiation, and will be managed by the Systems Monitoring Program.

LRA Section 3.3.2.2 states that components made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff's review of LRA Section 3.3.2.2 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.3.2.2-2, dated October 12, 2004, the staff noted that numerous line items In LRA Table 3.3.2.2 state that carbon and low-alloy steel components in fuel oil experience no AERMs and require no AMPs. This is not consistent with the GALL Report or with industry experience. Notes associated with these line items indicate that the AERMs identified in the GALL Report for this material/environment combination are not applicable (Note I) for the following reasons: (1) pitting, crevice, general, or galvanic corrosion are not concerns because there is no water collection in these components (Note 5, applied to fittings, piping, pumps, restricting orifice, strainers, and tubing); (2) biofouling is not a concern (Note 7, applied to tanks); or (3) galvanic corrosion is not a concern because there are no galvanic couples in the portions of the system where water could accumulate and provide a conductor (applied to tanks). Adjacent line items in LRA Table 3.3.2.2 for the same material, environment, and GALL reference state that the components are subjected to loss of material due to MIC and credit the Fuel Oil Chemistry Program and the One-Time Inspection Program for aging management. Therefore, the staff requested the applicant to clarify the above AMR and whether the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited for all carbon steel and low-alloy components in the system.

In its response, by letter dated November 3, 2004, the applicant clarified that the AMR line items that state that carbon and low-alloy steel components in fuel oil experience no AERMs are there to indicate that some potential aging mechanisms identified in the GALL Report are not applicable. GALL Report, Volume 2, Section VII.G.8-a, lists the four aging mechanisms as general, galvanic, pitting, and crevice corrosion, while the applicant's AMR determined that the only aging mechanism applicable to these components (where there is no water accumulation) is MIC. MIC forms the basis of the adjacent AMR line item. The applicant also clarified that the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited as aging managements programs for all carbon steel and low-alloy steel components in the fuel oil system with a fuel oil internal environment. The staff concurred with the applicant's assessment that MIC is the predominant aging effect for carbon and low-alloy steel in fuel oil where there is no potential for water accumulation. The staff also noted that the inspections performed on this system will identify the AERMs in the GALL Report, if they are present. Therefore, the staff found that the applicant had identified the appropriate aging effects.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the fuel oil system.

LRA Table 3.3.2.2 identifies the following AMPs for managing the aging effects described above: Fuel Oil Chemistry Program, One-Time Inspection Program, and the Systems Monitoring Program. The staff's detailed reviews of these AMPs are found in SER Sections 3.0.3.2.18, 3.0.3.1.7, and 3.0.3.3.1, respectively.

In RAI 3.3.2.2-1, dated October 12, 2004, the staff stated that LRA Section 3.3.2.2. implies that the one-time inspections will be limited to the system locations where contaminants are expected to accumulate; however, AERMs (particularly MIC) are identified for a larger population of components. Therefore, the staff requested the applicant to clarify the use of the one-time inspections. In its response, by letter November 3, 2004, the applicant stated that the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited as AMPs for all components in the fuel oil system with a fuel oil internal environment where aging effects were identified. These programs are being applied to all components with identified AERMs; therefore, the staff found this acceptable.

For the flexible hoses made of elastomer (rubber) in a fuel oil environment, the LRA credits the One-Time Inspection Program to manage the aging effect of elastomer degradation due to oxidation. The One-Time Inspection Program is typically used to verify that an aging effect is not occurring or when an aging effect is expected to occur slowly, such that the component intended function can be maintained for the extended period of operation. For these same hoses, the LRA credits the Systems Monitoring Program to manage the aging effect of elastomer degradation due to ultraviolet radiation. The Systems Monitoring Program provides for visual inspections of the hoses. The staff found the periodic inspections, combined with the one-time inspection of the hose internal surface, adequate for managing the aging of the flexible hoses. Therefore, the staff found the management of these hoses to be acceptable.

The staff reviewed LRA Table 3.3.2.2, which summarized the results of AMR evaluations for the fuel oil system component groups. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERMs for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

On the basis of its review of the information provided in the LRA and RAI responses, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the above fuel oil system components. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

<u>No Aging Effect or Aging Management Program Identified</u>. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERMs for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

3.3.2.3.3 Residual Heat Removal Service Water System – Summary of Aging Management Evaluation – Table 3.3.2.3

The staff reviewed LRA Table 3.3.2.3, which summarizes the results of AMR evaluations for the RHRSW system component groups.

In LRA Table 3.3.2.3, the applicant identifies aging effect for the RHRSW system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, and valves made from aluminum alloy in an environment of treated water (internal) are subjected to crack initiation and growth due to SCC, and loss of material due to crevice and pitting corrosion, and will be managed by the Chemistry Control Program and the One-Time Inspection Program. Fittings, piping, and valves made from carbon and low-alloy steel in an environment of treated water (internal) are subject to loss of material due to crevice, general, and pitting corrosion. Fittings made from polymer in environments of inside air (external) and treated water (internal) experience no AERMs and require no AMPs.

Through a staff teleconference follow up request dated February 11, 2005, the staff requested the applicant to provide additional clarification regarding the type of elastomer or polymer, its environment, and justification that there are no AERMs for the elastomer or polymer components. In its response, by letter dated March 11, 2005, the applicant clarified that the polymer components in this system are Derlin (acetal) insulating couplings between dissimilar material threaded piping. Based on its review of the material data sheet for Derlin, the staff concluded that the material is rated for continuous service in environmental conditions (e.g., temperature) significantly in excess of the conditions in the RHRSW system. Therefore, the staff concurred with the applicant's evaluation that there are no AERMs for the polymer components in this system.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the RHRSW.

No Aging Effect or Aging Management Program Identified. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an embedded/encased environment on their external surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that no aging effects are identified for embedded/encased components. If excessive corrosion that could prevent the performance of the intended functions during the period of extended operation was detected on the inside surface or outside surface in air environments adjacent to the embedded/encased portions, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

The staff concluded that the applicant's determination of no AERMs for components in the RHRSW system in an embedded/encased environment is acceptable since exposure to a corrosive environment will be limited. Inspections will be performed on adjacent surfaces exposed to an air environment. If corrosion was detected on adjacent surfaces in an air environment, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

3.3.2.3.4 Raw Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.4

The staff reviewed LRA Table 3.3.2.4, which summarizes the results of AMR evaluations for the raw cooling water system component groups.

In LRA Table 3.3.2.4, the applicant identifies aging effect for the raw cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs; expansion joints made from elastomer exposed to inside air (external) and raw water (internal) experience no AERMs and require no AMPs; fittings and piping made from polymer in air/gas (internal) or inside air (external) environments experience no AERMs and require no AMPs.

In the general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the elastomer components are fabric reinforced expansion joints (Garlock Style 204) made from chlorobutyl/polyester. The coating cover reduces ultraviolet radiation to negligible levels, the system temperature is low relative to the qualified temperature, and the elastomers are not exposed to significant radiation. Based on the above, the staff concurred with the applicant's conclusion that there are no AERMs for the elastomer components in this system.

With respect to the polymer components, by the letter dated March 11, 2005, the applicant clarified that the polymer components are molded plastic fittings and piping in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the raw cooling water system.

3.3.2.3.5 Raw Service Water System – Summary of Aging Management Evaluation – Table 3.3.2.5

The staff reviewed LRA Table 3.3.2.5, which summarizes the results of AMR evaluations for the raw service water system component groups.

In LRA Table 3.3.2.4, the applicant identifies the aging effects of the service water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR line items that do not rely on the GALL Report are as follows: fittings and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In a general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.1.

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 RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.6 High Pressure Fire Protection System – Summary of Aging Management Evaluation – Table 3.3.2.6

The staff reviewed LRA Table 3.3.2.6, which summarizes the results of AMR evaluations for the high pressure fire protection system component groups.

In LRA Section 3.3.2.1.6 and Table 3.3.2.6, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, alloy steel, stainless steel, aluminum, cast iron, elastomers, glass, and copper alloys.

The applicant identified the environments to which these materials could be exposed as air and gas (wetted, ambient and dry), raw water (well water), treated water and AFFF and includes environments inside, outside, and buried. The applicant identified loss of material (from corrosion or leaching) and degradation (UV degradation of elastomers) as the aging effects associated with the fire water system.

Staff Evaluation. The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the fire protection system during the period of extended operation, as required by the regulations that govern LRA. The staff also reviewed LRA Sections of 3.3.2.6 and Table 3.3.2.6 for completeness and consistency with the GALL Report and industry experience.

On the basis of its review of the LRA, the staff found that the aging effects resulting from exposure of the fire water system components to the environments described in LRA

Table 3.3.2.6 are consistent with the GALL Report and with industry experience for these material-environment combinations. Therefore, the staff found that the applicant identified the applicable aging effects and associated AMPs and that they are appropriate for the combination of materials and environments listed.

3.3.2.3.7 Potable Water System – Summary of Aging Management Evaluation – Table 3.3.2.7

The staff reviewed LRA Table 3.3.2.7, which summarizes the results of AMR evaluations for the potable water system component groups.

In LRA Table 3.3.2.7, the applicant stated the aging effects of the potable water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, tubing, and valves made from copper alloy and exposed to inside air, which experience no AERMs and require no AMPs; fittings and piping made from carbon and low-alloy steel in raw water for loss of material due to galvanic, general, crevice and pitting corrosion, which will be managed by the One-Time Inspection Program. LRA Section 2.3.3.7 clarifies that the raw water is potable water supplied by the city of Athens, Alabama. LRA Table 3.3.2.7 notes clarify that the water is chlorinated to prevent the growth of microorganisms, such that biofouling and MIC are not expected, but that chlorination introduces the possibility of SCC for the stainless steel components. For valves made from carbon and low-alloy steel in raw water, loss of material due to general, crevice, and pitting corrosion will be managed by the One-Time Inspection Program. For fittings made from cast iron and cast iron alloy in raw water, loss of material due to general, crevice, pitting, and galvanic corrosion will be managed by the One-Time Inspection Program. For valves made from cast iron and cast iron alloy (gray) in raw water, loss of material due to general, crevice, pitting, and galvanic corrosion will be managed by the One-Time Inspection Program. For fittings and valves made from stainless steel in raw water, crack initiation and growth due to SCC will be managed by the One-Time Inspection Program. For fittings, tubing, and valves made from copper alloy in raw water, loss of material due to crevice and pitting corrosion will be managed by the One-Time Inspection Program.

In general RAI 3.3.2.2-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff also noted that for the carbon and low-alloy exposed to raw water, galvanic corrosion is identified as a potential aging effect for the fittings and piping, but not for the valves. In its March 11, 2005, response to the staff's informal request February 11, 2005, the applicant clarified that galvanic corrosion is only applicable when the component is in contact with a more cathodic material, and that the valves in question are not connected to more cathodic materials. The staff found this explanation reasonable and acceptable.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the potable water system.

Loss of Material due to Corrosion for Copper Alloys in a Raw Water Environment. The applicant identified loss of material due to crevice and pitting corrosion for components constructed of copper alloy and stainless steel in a raw water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.3.2.7 for the potable water system evaluates the potable (city) water as a raw water source. The actual chemistry is much milder than expected for raw water. Therefore, loss of material affecting component operation during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since raw water for this system is actually potable water, which has a milder chemistry. Therefore, the potential for corrosion is low. The One-Time Inspection Program will verify that corrosion is not occurring. If corrosion is detected, additional inspections and corrective actions will be taken.

3.3.2.3.8 Ventilation System – Summary of Aging Management Evaluation – Table 3.3.2.8

The staff reviewed LRA Table 3.3.2.8, which summarizes the results of AMR evaluations for the ventilation system component groups.

In LRA Table 2.3.3-8, the applicant lists individual system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: ducting made from carbon and low-alloy steel in air/gas (internal) and elastomer - rubber and silicone rubber in air/gas (internal) experience no AERMs and require no AMPs. Elastomer - rubber and silicone rubber in air/gas (external) experience elastomer degradation due to ultraviolet radiation.

In RAI 3.3.2.1.8-1, dated December 10, 2004, the staff requested additional information regarding the applicant's claim in LRA Table 3.3.2.8 that the carbon and low-alloy steel ductwork experiences no aging effects. The staff noted that adjacent entries in LRA Table 3.3.2.8 for the same material, environment, and GALL Report reference identify a loss of material due to general corrosion. It appeared to the staff that the applicant takes exception to the GALL Report's identification of crevice corrosion, pitting corrosion, and MIC as not applicable while general corrosion is applicable. In its response, by letter November 3, 2004, the applicant confirmed that the AMR was intended to state that the applicant took exception to the GALL-identified AERMs of crevice corrosion, pitting corrosion, and MIC, because the GALL identifies these AERMs for drip pans and drain lines, which are typically wet. Instead, the applicant identifies general corrosion (in adjacent line items) and credits the One-Time Inspection Program. The staff found the applicant's response acceptable because the applicant stated that the ducting is not expected to be wetted. The staff also found that the one-time inspection will be adequate to identify a loss of material in the ducting.

The technical staff also questioned the AMR items related to elastomer - rubber and silicone rubber ductwork in air/gas and inside air. For these material/environment combinations, the applicant claims that there are no AERMs based on industry guidance. The degradation of elastomers depends on environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals. Degradation can also be caused by wear (for items such as seals and vibration dampers). The staff asked the applicant to provide additional information on the above factors to justify that there are no AERMs for the elastomers, or to provide aging management for the elastomer components in the ductwork. In its response dated November 3, 2004, the applicant clarified that the elastomer degradation due to ultraviolet radiation is identified (in adjacent LRA Table 3.3.2.8 AMR items) and managed by the Systems Monitoring Program. The applicant did not identify elastomer degradation due to thermal exposure or ionizing radiation because the components in question remain below the thresholds for significant degradation from these factors. Based on the above, the staff found that the applicant had adequately addressed the concerns; therefore, the RAI 3.3.2.1.8-1 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 found the aging effects of the above ventilation system component types that are 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the ventilation system.

On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects for the ventilation system components that are not addressed by the GALL Report so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.9 Heating, Ventilation, and Air Conditioning System – Summary of Aging Management Evaluation – Table 3.3.2.9

The staff reviewed LRA Table 3.3.2.9, which summarizes the results of AMR evaluations for the HVAC system component groups.

In LRA Table 2.3.3.9, the applicant lists individual system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following:

Components in raw water (potable): for the carbon and low-alloy steel components (fittings, heat exchangers, strainers, tanks and valves), the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. For the cast iron and cast iron alloy components (fittings, heat exchangers, pumps, and valves), the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. In addition, for the cast iron and cast iron alloy heat exchangers, the applicant also identifies selective leaching, and credits the Selective Leaching of Materials Program (as clarified by letter dated March 11, 2005). For the stainless steel components (fittings, flexible connectors, heat exchangers, piping and valves), the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the One-Time Inspection Program. For the copper alloy components (fittings, heat exchangers, tubing, and valves), the applicant identifies loss of material due to crevice, galvanic, and pitting corrosion, and credits the One-Time Inspection Program.

Components in treated water: for the carbon and low-alloy steel components (fittings, heat exchangers, piping, strainers, tanks and valves), the applicant identifies galvanic corrosion and credits the Closed-Cycle Cooling Water System Program. For the stainless steel components (fittings, flexible connectors, piping, pumps, strainers, tubine and valves), the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the Closed-Cycle Cooling Water System Program.

Components in raw water: for carbon steel and low-alloy steel piping, the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. For stainless steel heat exchangers, the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the One-Time Inspection Program.

In addition to the above aging effects, the applicant identifies loss of heat transfer due to particulate fouling, and credits the One-Time Inspection Program, for heat exchanger components made from aluminum alloy, copper alloy, and stainless steel in raw water (potable), raw water, and air/gas environments.

The applicant identified no aging effects and, consequently, no AMPs, for polymer components (fittings, flexible connectors, tubing and valves) in air/gas (internal) and inside air (external), elastomer ductwork and flexible connectors in air/gas (internal) or inside air (external), and copper alloy components in inside air (external).

In general RAI 3.3.2.2-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff asked for additional information related to elastomer components, since the applicant determined that there are no AERMs based on industry guidance. The degradation of elastomers depends on the environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals (aggressive chemicals are not anticipated for this system). In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005, the applicant demonstrated that the temperature and radiation levels remain below the thresholds for which there is significant aging of the silicon and neoprene components, the neoprene coated glass material (Dupont's Ventglass). Therefore, the staff concurred with the applicant's assessment.

With respect to the polymer components, by letter dated March 11, 2005, the applicant clarified that the polymer components are molded plastic (valves), molded nylon (fittings), hypalon coated nylon (flexible connectors), and Nycoa Nylon 589 (tubing) in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for these polymers and environments, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

In RAI 3.3.2.1.9-2, dated October 12, 2004, the staff stated that in Table 3.3.2.1.9 the applicant claimed that there are no AERMs for this material environment combination of copper-alloy heat exchanger in inside air (external). Condensation in the heat exchangers could lead to aging effects, and there is the potential for loss of heat transfer by such mechanisms as particulate fouling. In its November 3, 2004, response, the applicant clarified that the coils are for cooling freon, so that there is no condensation. Also, due to the design of the cooling coils (no fins), they are not susceptible to particulate fouling. Since there will be no condensation on the coils and since the design is not susceptible to particulate fouling, the staff agreed with the applicant's assessment. Therefore, the staff found the applicant's response acceptable and RAI 3.3.2.1.9-2 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 RAIs, the staff found the aging effects of the above heating, ventilation, and air conditioning system component types that are 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the heating, ventilation, and air conditioning system.

<u>Crack Initiation and Growth due to SCC for Copper Alloys and Stainless Steel in Raw Water Environments</u>. The applicant identified crack initiation and growth due to SCC as an AERM for heat exchangers constructed of stainless steel in a raw water environment. The applicant credited the One-Time Inspection Program to manage this aging effect. The staff inquired as to the technical basis for identifying this aging effect for this material and environment combination. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that, upon further review, the cracking aging effect was inappropriately identified for the raw water environment and should be deleted from the Table 3.3.2.9 entry for these components.

The staff concluded that the applicant’s response is acceptable for this material and environment combination since the conditions for SCC are not expected to be present in the environment identified.

<u>Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments</u>. The applicant identified crack initiation and growth due to SCC as an AERM for fittings, flexible connectors, piping, tubing and valves constructed of stainless steel in a treated water environment. The applicant credited the Closed-Cycle Cooling Water System Program to manage this aging effect. During the onsite audit, the staff inquired as to how the Closed-Cycle Cooling Water System Program would detect cracking prior to the loss of intended function for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that, upon further review, the cracking aging effect is unnecessary for these components. In addition, components were identified with cracking of stainless steel in a raw water environment in potable water, and heating, ventilation systems, and air conditioning. The applicant determined that this cracking aging effect is also unnecessary.

The staff concluded that the applicant's response is acceptable for this material and environment combination since the conditions conducive to SCC are not present in the system identified.

Loss of Material Due to Corrosion for Cast Iron and Carbon/Low Alloy Steels in an Air/Gas Environment. The applicant identified loss of material due to crevice, galvanic, general, and pitting corrosion as an AERM for heat exchangers constructed of cast iron and cast iron alloy, as well as heaters and heat exchangers constructed of carbon or low-alloy steel in an air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for components with these material and environment combinations in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the components in the heating, ventilation, and air conditioning system located in an air/gas environment were exposed to heated and cooled circulated air. Loss of material is consistent with the GALL Report, although the GALL Report identifies only general corrosion. Based on the potential for water accumulation on or in the area of the cooling coils, additional potential aging mechanisms were identified. Actual experience based on a review of work orders and PERs demonstrates that loss of material has not been an issue for these components within this system. In particular, no instances of pitting, crevice, or galvanic corrosion were identified in this review. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since these components are normally exposed to heated and cooled air and the potential for loss of material due to crevice, galvanic, and pitting corrosion is low. Loss of material due to crevice, galvanic, and pitting corrosion of these components was included since there is the potential for water accumulation near them; however, a review of past operating experience confirms that this aging effect has not been a problem. The One-Time Inspection Program will verify that loss of material is not occurring. If loss of material is detected, additional inspections and corrective actions will be taken.

Fouling Product Buildup due to Particulate for Copper Alloy and Stainless Steel in an Air/Gas Environment. The applicant identified fouling product buildup due to particulate as an AERM for heat exchangers constructed of copper alloy and stainless steel in an air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the air/gas environment to which the cooling coils are exposed is heated and cooled circulated air. The actual plant experience based on a review of work orders and problem reports demonstrates that fouling has not been an issue with this system. The One-Time Inspection Program will verify this by performing a sampling inspection. If fouling is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable. These components are normally exposed to heated and cooled air and the potential for fouling due to particulate is low.

A review of past operating experience confirms that this aging effect has not been a problem, and the One-Time Inspection Program will verify that fouling is not occurring. If fouling is detected, additional inspections and corrective actions will be taken.

Fouling Product Buildup due to Particulate for Stainless Steel in a Raw Water Environment. The applicant identified fouling product buildup due to particulate as an AERM for heat exchangers constructed of stainless steel in a raw water environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water referred to in this line item is actually potable (city) water. The chemistry of the potable water is much milder than expected for raw water. Therefore, loss of material and fouling potentially affecting component operability during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion or fouling is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since the raw water referred to in this line item is actually potable (city) water. The chemistry of the potable water is much milder than expected for raw water. Therefore, loss of material and fouling potentially affecting component operability during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection.

No Aging Effect or Aging Management Program Identified. The applicant identified no aging effect or AMP for heat exchangers constructed of aluminum alloy and copper alloy in an outside air environment on the external surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the cooling coils identified in an outside environment are in the Freon cycle and the air flow over the coils is to cool the Freon. Therefore, condensation on the coils will not occur and loss of material is not identified as an aging mechanism requiring management for the period of extended operation. Air side fouling of cooling coils that have no condensation mechanism is only a problem for fin type heat exchangers. Therefore, fouling is not identified as an aging mechanism requiring management for the period of extended operation.

The staff concluded that the applicant's response is acceptable since these components are cooling coils exposed to air flow on the outside surface. The air flow is to cool Freon inside the coils; therefore, the air will be heated and condensation will not occur on these components. The applicant also identified no aging effect or AMP for heat exchangers constructed of copper alloy in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff onsite audit questions that Table 3.3.2.9, rows 131 and 132 are referring to the Freon side of the cooling coil and correctly identify no aging effects. The material should reference Freon in the materials description. These items are for the external surface of cooling coils and correctly identify loss of material.

The staff concluded that the applicant’s response is acceptable since the components will be exposed to Freon, which is not a corrosive environment for copper alloys; and also concurred with the corrections to Table 3.3.2.9, rows 131 and 132

3.3.2.3.10 Control Air System – Summary of Aging Management Evaluation – Table 3.3.2.10

The staff reviewed LRA Table 3.3.2.10, which summarizes the results of AMR evaluations for the control air system component groups.

In LRA Table 3.3.2.10, the applicant identifies the aging effects of the control air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: for fittings made from carbon and low-alloy steel in inside air, the applicant identifies loss of material due to general corrosion and credits the Systems Monitoring Program. For components (heat exchangers, piping, and valves) made from carbon and low-alloy steel in treated water, the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the Closed-Cycle Cooling Water System Program. Fittings, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

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 found the aging effects of the above control air system component types that are 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the control air system.

3.3.2.3.11 Service Air System – Summary of Aging Management Evaluation – Table 3.3.2.11

The staff reviewed LRA Table 3.3.2.11, which summarizes the results of AMR evaluations for the service air system component groups.

In LRA Section 3.3.2.11 and Table 3.3.2.11, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, alloy steel, stainless steel, cast iron, and cast iron alloy. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material and loss of bolting function due to general corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the service air system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.11 and Table 3.3.2.11 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant 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).

3.3.2.3.12 CO_2 System – Summary of Aging Management Evaluation – Table 3.3.2.12

In Section 3.3.2.12 and LRA Table 3.3.2.12, the applicant identified the materials, environments, and AMR. The materials identified include carbon steel, alloy steel, stainless steel, aluminum, cast iron, elastomers, glass, and copper alloys. The applicant identified the environments to which these materials could be exposed as inside air and gas. The applicant identified loss of material from corrosion as the aging effect associated with the CO_2 system components.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the CO_2 system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.12 and Table 3.3.2.12 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had 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).

3.3.2.3.13 Station Drainage System – Summary of Aging Management Evaluation – Table 3.3.2.13

The staff reviewed LRA Table 3.3.2.13, which summarizes the results of AMR evaluations for the station drainage system component groups.

In LRA Table 3.3.2.13, the applicant identifies the aging effects of the station drainage system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the applicant's November 3, 2004, response to the staff's RAI, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the station drainage system valves made from copper alloy and exposed to inside air will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.14 Sampling and Water Quality System – Summary of Aging Management Evaluation – Table 3.3.2.14

The staff reviewed LRA Table 3.3.2.14, which summarizes the results of AMR evaluations for the sampling and water quality system component groups.

In LRA Table 3.3.2.14, the applicant identified the aging effects of the sampling and water quality system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Polymer components (fittings, strainers, tubing, and valves) exposed to air/gas, inside air, and treated water experience no AERMs and require no AMPs. Panel (Open sample panel) made from carbon and low-alloy steel in inside air (external) is subject to loss of material due to general corrosion.

In general RAI 3.3.2.1-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

With respect to the polymer components, in its response to the staff's informal request of February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the polymer components are teflon fittings in treated water, air/gas, and inside air, polymer strainers in treated water and inside air, and polymer tubing and valves in treated water, air/gas, and inside air environments. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the sampling and water quality system.

3.3.2.3.15 Building Heat System – Summary of Aging Management Evaluation – Table 3.3.2.15

The staff reviewed LRA Table 3.3.2.15, which summarizes the results of AMR evaluations for the building heat system component groups.

In LRA Table 3.3.2.15, the applicant identifies the aging effects of the building heat system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: heaters made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.1.

On the basis of its review of the information provided in the LRA, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above building heat system components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.16 Raw Water Chemical Treatment System – Summary of Aging Management Evaluation – Table 3.3.2.16

The staff reviewed LRA Table 3.3.2.16, which summarizes the results of AMR evaluations for the raw water chemical treatment system component groups.

In LRA Table 3.3.2.16, the applicant identifies the aging effects of the raw water chemical treatment system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: nickel alloy components (fittings, piping, and restricting orifice) exposed to raw water experience loss of material due to biofouling, MIC, crevice and pitting corrosion, and are managed by the One-Time Inspection Program, while nickel alloy components (fittings, piping, and restricting orifice) exposed to outside air experience no AERMs and require no AMPs.

On the basis of its review of the information provided in the LRA, the staff found the aging effects of the above raw water chemical treatment system AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the raw water chemical treatment system.

<u>Loss of Material due to Biofouling, MIC, Crevice and Pitting Corrosion for Nickel Alloys in a Raw Water Environment</u>. The applicant identified loss of material due to biofouling, MIC, crevice and pitting corrosion for components constructed of nickel alloy in a raw water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for this material/environment combination for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water referred to in this line item is a diluted raw water chemical treatment solution. The diluted chemicals in these nickel alloy components minimize any aging effects that potentially affect component operability during the period of extended operation. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant’s response is acceptable since the raw water referred to in this line item is a diluted raw water chemical treatment solution. The diluted chemicals in these nickel alloy components minimize any aging effects that potentially affect component operability during the period of extended operation.

<u>No Aging Effect or Aging Management Program Identified</u>. The applicant identified no aging effect or AMP for fittings, piping, and valves constructed of polymer with a raw water environment on the internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the polymer referred to in Table 3.3.2.16 is the internal surface of polypropylene-lined carbon steel components. The LRA does not credit the lining for prevention of corrosion and this material/environment combination should be deleted.

The staff found that the applicant’s response is acceptable, because the LRA does not credit the lining for prevention of corrosion on the internal surface, and also concurred with the correction to LRA Table 3.3.2.16 to delete this material/environment combination.

3.3.2.3.17 Demineralizer Backwash Air System – Summary of Aging Management Evaluation – Table 3.3.2.17

The staff reviewed LRA Table 3.3.2.17, which summarizes the results of AMR evaluations for the demineralizer backwash air system component groups.

In LRA Table 3.3.2.17, the applicant identifies the aging effects of the demineralizer backwash air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: traps and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Traps made from copper alloy and exposed to air/gas (internal)-pooled moisture experience loss of material due to selective leaching.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

LRA Table 3.3.2.17 identifies the Selective Leaching of Materials Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.1.8.

On the basis of its review of the information provided in the LRA, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above demineralizer backwash air system components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.18 Standby Liquid Control System – Summary of Aging Management Evaluation – Table 3.3.2.18

The staff reviewed LRA Table 3.3.2.18, which summarizes the results of AMR evaluations for the standby liquid control system component groups.

In LRA Table 3.3.2.18, the applicant identified the aging effects of the standby liquid control system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: polymer (Derlin) fittings exposed to inside air and treated water experience no aging effects and require no aging management. Fittings made of carbon and low-alloy steel and exposed to air/gas (internal) experience loss of material due to general corrosion.

In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005,
the applicant stated that the Derlin is used as insulating flanges to prevent galvanic corrosion. Based on its review of industry experience, the applicant determined that there are no AERMs for Derlin in this application. Based on its review of the standby liquid control system and the material property data sheet for Derlin, the staff concurred with the applicant's assessment.

LRA Table 3.3.2.18 identifies the One-Time Inspection Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.1.7.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.19 Off-Gas System – Summary of Aging Management Evaluation – Table 3.3.2.19

The staff reviewed LRA Table 3.3.2.19, which summarizes the results of AMR evaluations for the off-gas system component groups.

In LRA Table 3.3.2.19, the applicant identified the aging effects of the off-gas system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: fittings made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Valves made of carbon and low-alloy steel in air/gas (internal) and inside air (external) are subject to loss of material due to general corrosion.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

LRA Table 3.3.2.19 identifies the following AMPs for managing the aging effects described above: One-Time Inspection Program and Systems Monitoring Program. The staff's detailed review of these AMPs is found in SER Sections 3.0.3.1.7 and 3.0.3.3.1.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.20 Emergency Equipment Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.20

The staff reviewed LRA Table 3.3.2.20, which summarizes the results of AMR evaluations for the emergency equipment cooling water system component groups.

In LRA Table 3.3.2.20, the applicant identifies the aging effects of the emergency equipment cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy heat exchanger subcomponents in an air/gas environment experience fouling due to particulate buildup, and are managed by the One-Time Inspection Program.

In a RAI 3.3.2.1.20-1, dated October 12, 2004. the staff asked for additional justification that there are no AERMs, including a loss of heat transfer, for the copper alloy heat exchanger components in this system. In its response, by letter November 3, 2004, the applicant stated that the components in question are the u-bend connectors for the internal cooling coil in the room coolers. These components are likely to be exposed to condensation and, therefore, may experience loss of material; however, they are external to the cooler such that loss of heat transfer is not a concern. The applicant proposes to use the Systems Monitoring Program to manage the identified aging effect. The staff found that the applicant had identified the appropriate aging effects for the above component and had proposed an acceptable AMP. Therefore, the staff found this 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 found the aging effects of the above emergency equipment cooling water 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the emergency equipment cooling water system. Therefore, RAI 3.3.2.1.20-1 is considered resolved.

3.3.2.3.21 Reactor Water Cleanup System – Summary of Aging Management Evaluation – Table 3.3.2.21

The staff reviewed LRA Table 3.3.2.21, which summarizes the results of AMR evaluations for the reactor water cleanup system component groups.

In LRA Table 3.3.2.21, the applicant identifies the aging effects of the reactor water cleanup system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Heat exchangers made of carbon and low-alloy steel and exposed to treated water (internal) experience loss of material due to crevice, general, and pitting corrosion.

In general RAI 3.3.2.1-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

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 found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

LRA Table 3.3.2.21 identifies the Closed-Cycle Water Cooling System Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.2.12.

<u>Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments</u>. The staff reviewed LRA Table 3.3.2.21, which summarized the results of AMR evaluations for the reactor water cleanup system component groups. The applicant identified crack initiation and growth due to SCC and change in material properties due to thermal aging as aging effects requiring management for valves constructed of stainless steel and CASS in a treated water environment. The applicant credited the ASME Section XI Inservice Inspection Program to manage these aging effects. During the onsite audit, the staff inquired as to the ASME class of these valves, whether they are currently included in the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program, and the basis for concluding that the ASME inspection will detect changes in material properties.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the CASS valves that are included in this line item are the reactor water cleanup system 1-inch root valves providing flow to and from the recently added durability monitoring panels for

Units 2 and 3. These valves are non-nuclear Code class, therefore, the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program is not applicable.

The applicant further stated that thermal embrittlement degrades the mechanical properties of material (strength, ductility, toughness) as a result of prolonged exposure to high temperatures. CASS materials are susceptible to thermal embrittlement. The degree of susceptibility is dependent upon material composition and time at temperature. The maximum time these valves would be exposed to these high temperatures would be for Unit 3. The Unit 3 valves were installed in the spring 2000 refueling outage with a proposed license expiration date of July 2, 2036. This represents a potential for approximately 36.5 years of operation at the elevated temperatures. The Unit 2 valves were installed in the spring 2001 refueling outage with a proposed license expiration date of June 28, 2034, or approximately 33.5 years of operation. None of these CASS valves will be operated beyond their original 40-year design life and thermal aging has not been identified as a current license basis (40 years) issue.

The applicant referenced NRC letter, "License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," dated May 19, 2000 from Mr. C. I. Grimes (NRC) to D. J. Walters (NEI), to support its position that change in material properties due to thermal aging is not a concern for these valves, citing the results of a bounding fracture mechanics analysis for valve bodies of less than 4-inch NPS, included in Attachment 2 to this letter.

The applicant concluded that thermal aging of these 1-inch NPS CASS valves is not an AERM, based on the following considerations:

- Thermal aging is not a CLB issue and is not a concern for operation beyond forty years. These valves will be operated for less than forty years, including the period of extended operation.
- Even assuming thermal aging for valves is a CLB concern, the conclusion from the NRC's bounding fracture analysis for valves less than NPS 4 was that "a CASS valve loaded to the maximum anticipated stress can sustain a through wall crack well in excess of its wall thickness without fracturing" and "that requirements for licensees to either (a) inspect . . . of these components would represent an unnecessary duplication of effort."

However, to resolve this issue, the applicant stated that thermal aging will be identified in the LRA as being an AERM for these 1-inch NPS non-Class 1 valves, and that the Systems Monitoring Program will be identified as the AMP to perform an external visual inspection.

The staff concluded that the applicant's response is acceptable on the basis that: (1) the valves have operating lives less than 40 years; (2) NRC-sponsored fracture mechanics analyses demonstrate a high degree of flaw tolerance, including through-wall cracking; and (3) periodic external visual examination conducted as part of the Systems Monitoring Program will detect through-wall cracking, in the unlikely event that it should occur.

During the onsite audit, the staff also asked why the BWR Stress Corrosion Cracking Program is not credited for this aging effect in all cases. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.3.2.21, lines 24 and 54 refer to fittings and piping that are less than 4-inch NPS. The corresponding GALL Report Volume 2, Item IV.C1.1-i, references the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program, and the One-Time Inspection Program. For fittings and piping greater than or equal to 4-inch NPS, line items 27 and 56 specify the BRW Stress Corrosion Cracking Program and the Chemistry Control Program, which is consistent with Item IV.C1.1-f. Table 3.3.2.21, line 102 credits the BWR Stress Corrosion Cracking Program and the chemistry control program for aging management of Valves-RCPB, which is consistent with IV.C1.3-c. Note that the BWR Stress Corrosion Cracking Program invokes the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program for inspection and flaw evaluation to monitor IGSCC.

The applicant further stated that LRA Table 3.3.2.21, rows 20, 49, and 93, for non-reactor coolant pressure boundary fittings, piping, and valves, respectively, incorrectly listed the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and/or BWR Stress Corrosion Cracking Program. The correct AMPs for rows 20, 49, and 93 are the Chemistry Control Program and One-Time Inspection Program.

The staff found that the applicant’s use of the ASME Code Section XI Program for components less than 4" NPS is consistent with the GALL Report, and also concurred with the applicant’s corrections to LRA Table 3.3.2.21. The staff found the applicant’s response to be acceptable.

3.3.2.3.22 Reactor Building Closed Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.22

The staff reviewed LRA Table 3.3.2.22, which summarizes the results of AMR evaluations for the reactor building closed cooling water system component groups.

In LRA Table 3.3.2.22, the applicant identifies the aging effects of the reactor building closed cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Carbon and low-alloy steel components (fittings, heat exchangers, piping, pumps, tanks, and valves) in treated water are exposed to loss of material due to general, pitting, crevice, and galvanic corrosion, and are managed by the Closed-Cycle Cooling Water System Program.

In general RAI 3.3.2.1-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

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 RAI, the staff found the aging effects of the above reactor building closed cooling water 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the reactor building closed cooling water system.

3.3.2.3.23 Reactor Core Isolation Cooling System – Summary of Aging Management Evaluation – Table 3.3.2.23

The staff reviewed LRA Table 3.3.2.23, which summarizes the results of AMR evaluations for the reactor core isolation cooling system component groups.

In LRA Table 3.3.2.23, the applicant identified the aging effects of the reactor core isolation cooling system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: heat exchangers, pumps, strainers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy fittings in treated water experience crack initiation and growth due to SCC and loss of material due to crevice, pitting, and galvanic corrosion, and are managed with the Chemistry Control Program and the One-Time Inspection Program. Copper alloy valves in treated water can experience loss of material due to flow-accelerated corrosion, and are managed through the Flow-Accelerated Corrosion Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In RAI 3.3.2.1.23-1, dated October 12, 2004, the staff requested the applicant to explain why loss of heat transfer is not an applicable AERM for the copper alloy heat exchanger components in inside air. In its response dated November 3, 2004, the applicant clarified that these components are the connectors for the lube oil lines going to the internal copper tubes. The staff concluded that heat transfer is not an intended function for these connectors. In addition, these connectors remain above ambient temperature, such that there is no condensation that would lead to other aging effects. The staff concurred that there will be no other aging effects in the absence of condensation or pooling. Based on the above, the staff found the applicant's response 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 RAI, the staff found the aging effects of the above reactor core isolation cooling 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the reactor core isolation cooling system.

3.3.2.3.24 Auxiliary Decay Heat Removal System – Summary of Aging Management Evaluation – Table 3.3.2.24

The staff reviewed LRA Table 3.3.2.24, which summarizes the results of AMR evaluations for the auxiliary decay heat removal system component groups.

In LRA Section 3.3.2.24 and Table 3.3.2.24, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, low-alloy steel, and stainless steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material from general and pitting corrosion and of bolting function due to general corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the auxiliary decay heat removal system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.24 and Table 3.3.2.24 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had 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).

3.3.2.3.25 Radioactive Waste Treatment System – Summary of Aging Management Evaluation – Table 3.3.2.25

The staff reviewed LRA Table 3.3.2.25, which summarizes the results of AMR evaluations for the radioactive waste treatment system component groups.

In LRA Table 3.3.2.25, the applicant identifies the aging effects of radioactive waste treatment system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

Carbon and low-alloy steel components (fittings, piping, and valves) in raw water experience loss of material due to general, crevice, and pitting corrosion, galvanic corrosion, and MIC, and are managed through the One-Time Inspection Program. Carbon and low-alloy steel components (fittings, piping, and valves) in treated water experience loss of material due to general, crevice, pitting, and galvanic corrosion, and are managed by the One-Time Inspection Program. For cast iron and cast iron alloy pumps in treated water, the applicant uses the One-Time Inspection Program to manage loss of material due to general, crevice and pitting corrosion.

For elastomer (neoprene and silicon) fittings in air/gas and inside air, the applicant does not identify any AERMs or AMPs.

Additional items the technical staff was also asked to review include the following AMR line items that do not rely on the GALL Report: aluminum alloy fittings and piping in treated water may experience crack initiation and growth due to SCC and a loss of material due to crevice and pitting corrosion, and are managed by the Chemistry Control Program and the One-Time Inspection Program, while the aluminum alloy in air experiences no AERMs. For the copper alloy (bronze) fittings, the bronze in treated water may experience a loss of material due to crevice and pitting corrosion and loss of material due to selective leaching, which are managed by the One-Time Inspection Program and Selective Leaching of Materials Program, respectively, while the bronze in inside air experiences no AERMs. For the cast iron and cast iron alloy strainers, the side exposed to treated water may experience loss of material due to general, crevice, and pitting corrosion and a loss of material due to selective leaching, which are managed by the One-Time Inspection Program and the Selective Leaching of Materials

Program, respectively, while the side in inside air experiences loss of material due to general corrosion and is managed through the Systems Monitoring Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In RAI 3.3.2.1.23-1, dated October 12, 2004, the staff asked for additional information related to elastomer components, since the applicant determined that there are no AERMs based on industry guidance. The degradation of elastomers depends on the environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals (aggressive chemicals are not anticipated for this system). In its response dated November 3, 2004, the applicant demonstrated that the temperature and radiation levels remain below the thresholds for which there is significant aging of the silicon and neoprene. Therefore, the staff concurred with the applicant's assessment.

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 RAIs, the staff found the aging effects of the above radioactive waste treatment 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 found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the radioactive waste treatment system.

3.3.2.3.26 Fuel Pool Cooling and Cleanup System – Summary of Aging Management Evaluation – Table 3.3.2.26

The staff reviewed LRA Table 3.3.2.26, which summarizes the results of AMR evaluations for the fuel pool cooling and cleanup system component groups.

In LRA Table 3.3.2.26, the applicant identifies the aging effects of the spent fuel pool cooling and cleanup system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: for aluminum alloy components (fittings, piping, and valves) in treated water, the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and galvanic corrosion, and credits the Chemistry Control Program and the One-Time Inspection Program.

On the basis of its review of the information provided in the LRA, the staff found the aging effects of the above spent fuel pool cooling and cleanup 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 found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the spent fuel pool cooling and cleanup system.

3.3.2.3.27 Fuel Handling and Storage System – Summary of Aging Management Evaluation – Table 3.3.2.27

The staff reviewed LRA Table 3.3.2.27, which summarizes the results of AMR evaluations for the fuel handling and storage system component groups.

In Section 3.3.2.27 and LRA Table 3.3.2.27, the applicant identified the materials, environments, and AERMs. The materials identified include aluminum alloy, carbon steel, low-alloy steel, and stainless steel. The applicant identified the environments to which these materials could be exposed as inside air and treated water. The applicant identified loss of material from crack initiation and growth due to stress corrosion; loss of material due to crevice, pitting, general, and galvanic corrosion of bolting function due to stress relaxation; and loss of material due to mechanical wear.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the service air system during the period of extended operation, as required by 10 CFR 54.21(a)(3). Additionally, the staff considered the aging effect loss of of bolting function due to stress relaxation, which is addressed in SER Section 3.3.2.36. The staff reviewed LRA Section 3.3.2.27 and Table 3.3.2.27 for completeness and consistency with the GALL Report and industry experience.

3.3.2.3.28 Diesel Generator System – Summary of Aging Management Evaluation – Table 3.3.2.28

The staff reviewed LRA Table 3.3.2.28, which summarizes the results of AMR evaluations for the diesel generator system component groups.

In LRA Table 3.3.2.28, the applicant identifies the aging effects of the diesel generator system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. For stainless steel fittings in treated water, the applicant identifies crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the Closed-Cycle Cooling Water Program. For flexible connectors made from elastomer and exposed to treated water (internal) and inside air (external), the applicant identifies elastomer degradation due to thermal exposure and credits the Systems Monitoring Program. For flexible connectors made from elastomer and exposed to inside air, the applicant identifies elastomer degradation due to thermal exposure and ultraviolet radiation, and credits the Systems Monitoring Program. LRA Table 3.3.2.28 also identifies wear as an AERM for the elastomer flexible connectors, and credits the Systems Monitoring Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

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 found the aging effects of the above diesel generator 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 found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the diesel generator system.

Crack Initiation and Growth due to SCC for Copper Alloys and Stainless Steel in Raw Water Environments. The applicant identified crack initiation and growth due to SCC as an AERM for heat exchangers constructed of copper alloy in a raw water environment. The applicant credited the Open-Cycle Cooling Water System Program to manage this aging effect. The staff asked how the Open-Cycle Cooling Water System Program will detect cracking prior to the loss of intended function for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Open-Cycle Cooling Water System Program is implemented by a variety of maintenance, inspection, and testing procedures. The primary method of detecting cracking in heat exchangers is eddy current testing in accordance with the heat exchanger program (NEDP-17). This procedure requires the heat exchanger engineer to coordinate and schedule heat exchanger activities. The actual inspections are scheduled as preventive maintenance tasks. In particular, the diesel generator cooling water heat exchangers are scheduled with a frequency of two years.

The staff concluded that the applicant’s response is acceptable for this material and environment combination since the Open-Cycle Cooling Water System Program is implemented by a variety of maintenance, inspection, and testing procedures, which include eddy current testing in accordance with the heat exchanger program. Eddy current testing will detect cracking.

3.3.2.3.29 Control Rod Drive System – Summary of Aging Management Evaluation – Table 3.3.2.29

The staff reviewed LRA Table 3.3.2.29, which summarizes the results of AMR evaluations for the CRD system component groups.

In LRA Table 3.3.2.29, the applicant identifies the aging effects of the CRD system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy fittings in treated water are subjected to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion, and are managed by the Chemistry Control Program and the One-Time Inspection Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

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 found the aging effects of the above CRD 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 found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the CRD system.

Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments The applicant identified loss of material due to corrosion as an AERM for fittings, piping, strainers, and valves constructed of stainless steel in a treated water environment. However, cracking due to SCC was only identified for valves. The staff inquired as to why cracking due to SCC was not identified for stainless steel fittings, piping, and strainers in a treated water environment for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that stainless steel components have the potential for corrosion if the chemistry control program is not properly implemented. However, stress corrosion cracking only requires an AMP where the normal operating temperature is greater than 140 °F. The AMR identifies that the CRD system RCPB components (valves) that interface with the reactor water cleanup system experience normal operating temperatures in excess of 140 °F. These closed valves are the only components in the CRD system that exceed 140 °F.

The staff concluded that the applicant’s determination that cracking due to SCC is only applicable to RCPB valves in the CRD system is acceptable since these are the only components that operate at temperatures above 140 °F.

3.3.2.3.30 Diesel Generator Starting Air System – Summary of Aging Management Evaluation – Table 3.3.2.30

The staff reviewed LRA Table 3.3.2.30, which summarizes the results of AMR evaluations for the diesel generator starting air system component groups.

In LRA Table 3.3.2.30, the applicant identifies the aging effects of the diesel generator starting air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, flexible connectors, piping, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Flexible connectors made of elastomer in an air/gas (internal) and inside air (external) environment exhibit no AERMs and require no AMPs. Strainers made of stainless steel in an air/gas (internal) and inside air (external) environment exhibit no AERMs and require no AMPs.

In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

Depending on the environmental conditions such as temperature, ultraviolet radiation, and aggressive chemicals, there is the potential for elastomers to experience aging effects and require aging management. The applicant was asked to clarify that there are no aging effects commensurate with the environment exposed to or to provide appropriate aging management for these components (as they have done for numerous other systems); however, the applicant discussed the diesel generator system instead.

By letter dated May 24, 2005 the applicant submitted additional information in regard to the management of elastomers in the diesel generator starting air system. The applicant clarified that the rubber flexible connector can be exposed to a maximum temperature of about 115 °F and, conservatively, thermal stress is considered an applicable aging effect. The applicant identified that the Systems Monitoring Program will be used to manage the external surface and the internal surface will be managed by the One-Time Inspection Program. The applicant also clarified that no specific recommendations were provided by the manufacturer regarding service life and appropriate inspections.

The staff reviewed the applicant’s response and found the response to be reasonable and acceptable because the applicant identified that the external and internal surfaces of the rubber flexible connectors will be managed by the Systems Monitoring Program and the One-Time Inspection Program, respectively. There is reasonable assurance that these AMPs are capable of detecting and correcting degradation of the elastomers caused by thermal or other environmental aging factors prior to adversely affecting the intended function of the components.

On the basis of its review of the information provided in the LRA and the RAI response, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above components of the diesel generator starting air system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.31 Radiation Monitoring System – Summary of Aging Management Evaluation – Table 3.3.2.31

The staff reviewed LRA Table 3.3.2.31, which summarizes the results of AMR evaluations for the radiation monitoring system component groups.

In LRA Table 3.3.2.31, the applicant identifies the aging effects of the radiation monitoring system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, pumps, strainers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Traps made from aluminum alloy exposed to raw water are subjected to crack initiation/growth due to SCC, and will be managed by the One-Time Inspection Program. Tubing made from polymer (tygon) in air/gas experience no AERMs and require no AMPs.

In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

With respect to the polymer components, in response to the staff's informal request of February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the polymer components are tygon tubing in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

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 found the aging effects of the above radiation monitoring 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 found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the radiation monitoring system

3.3.2.3.32 Neutron Monitoring System – Summary of Aging Management Evaluation – Table 3.3.2.32

The staff reviewed LRA Table 3.3.2.32, which summarizes the results of AMR evaluations for the neutron monitoring system component groups.

In LRA Section 3.3.2.32 and Table 3.3.2.32, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, and low-alloy steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material from crack initiation and growth due to stress corrosion and cyclic loading, loss of bolting function due to general corrosion and wear and loss of material due to crevice and pitting corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the neutron monitoring system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.32 and Table 3.3.2.32 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had 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).

3.3.2.3.33 Traversing In-Core Probe System – Summary of Aging Management Evaluation – Table 3.3.2.33

The staff reviewed LRA Table 3.3.2.33, which summarizes the results of AMR evaluations for the traversing in-core probe system component groups.

In LRA Section 3.3.2.33 and Table 3.3.2.33, the applicant identified the materials, environments, and AERMs. The materials identified include stainless steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant has not identified any loss of material nor any aging effects.

The staff reviewed LRA Section 3.3.2.33 and Table 3.3.2.33 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant 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).

3.3.2.3.34 Cranes System – Summary of Aging Management Evaluation – Table 3.3.2.34

The staff reviewed LRA Table 3.3.2.34, which summarizes the results of AMR evaluations for the cranes system component groups.

In Section 3.3.2.34 and LRA Table 3.3.2.34, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, and low-alloy steel. The applicant identified the environments to which these materials could be exposed as inside air. The applicant identified loss of material from crack initiation, loss of bolting function due to stress relaxation and wear, loss of material due to general corrosion and mechanical wear.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the cranes system during the period of extended operation, as required by 10 CFR 54.21(a)(3). Additionally, the staff considered the aging effect, loss of of bolting function due to stress relaxation, which is addressed in SER Section 3.3.2.36. The staff reviewed LRA Section 3.3.2.34 and Table 3.3.2.34 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant 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).

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not evaluated in the GALL Report for entries shown in Table 3.3-1. The staff found that the applicant had 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 LRA Table 3.3.2.9, which summarized the results of AMR evaluations for the heating, ventilation, and air conditioning system component groups.

The applicant identified no aging effect or AMP for heat exchangers constructed of aluminum alloy and copper alloy in an outside air environment on the external surface. The staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the cooling coils identified in an outside environment are in the Freon cycle and the air flow over the coils is to cool the Freon. Therefore, condensation on the coils; will not occur and loss of material is not identified as an aging mechanism requiring management for the period of extended operation. Air side fouling of cooling coils that have no condensation mechanism is only a problem for fin type heat exchangers. Therefore, fouling is not identified as an aging mechanism requiring management for the period of extended operation.

The staff concluded that the applicant's response is acceptable since these components are cooling coils exposed to air flow on the outside surface. The air flow is to cool Freon inside the coils; therefore, the air will be heated and condensation will not occur on these components. The applicant also identified no aging effect or AMP for heat exchangers constructed of copper alloy in an air/gas environment on their internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.3.2.9, rows 131 and 132 are referring to the Freon side of the cooling coil and correctly identify no aging effects. The material should reference Freon in the materials description. These items are for the external surface of cooling coils and correctly identify loss of material.

The staff concluded that the applicant's response is acceptable since the components will be exposed to Freon, which is not a corrosive environment for copper alloys. The staff also concurred with the corrections to Table 3.3.2.9, rows 131 and 132.

The staff reviewed LRA Table 3.3.2.2, which summarized the results of AMR evaluations for the fuel oil system component groups. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERM for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

The staff reviewed LRA Table 3.3.2.3, which summarized the results of AMR evaluations for the residual heat removal service water system component groups.

The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an embedded/encased environment on their external surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that no aging effects are identified for embedded/encased components. If excessive corrosion that could prevent the performance of the intended functions during the period of extended operation was detected on the inside surface or outside surface in air environments adjacent to the embedded/encased portions, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

The staff concluded that the applicant's determination of no AERM for components in the residual heat removal service water system in an embedded/encased environment is acceptable since exposure to a corrosive environment will be limited. Inspections will be performed on adjacent surfaces exposed to an air environment. If corrosion is detected on adjacent surfaces in an air environment, corrective actions will be taken to restore the component, including the embedded/encased portions, if this is determined to be necessary.

The staff reviewed LRA Table 3.3.2.16, which summarized the results of AMR evaluations for the raw water chemical treatment system component groups.

The applicant identified no aging effect or AMP for fittings, piping, and valves constructed of polymer with a raw water environment on the internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the polymer referred to in Table 3.3.2.16 is the internal surface of polypropylene-lined carbon steel components. The LRA does not credit the lining for prevention of corrosion and this material/environment combination should be deleted.

The staff found that the applicant’s response is acceptable, because the LRA does not credit the lining for prevention of corrosion on the internal surface. The staff also concurred with the correction to Table 3.3.2.16, to delete this material/environment combination.

3.3.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging on the auxiliary systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the auxiliary systems, as required by 10 CFR 54.21(d).

3.4 <u>Aging Management of Steam and Power Conversion System</u>

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups associated with the following systems:

- main steam
- condensate and demineralized water
- feedwater
- heater drains and vents
- turbine drains and miscellaneous piping
- condenser circulating water
- gland seal water

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant provided AMR results for components. In LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the steam and power conversion system components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit, during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with 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 had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.4.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.4.2.2. The staff's audit evaluations are documented in the audit and review report and are summarized in SER Section 3.4.2.2.

In the onsite audit, the staff conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed were appropriate for the combinations of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.4.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.4.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the steam and power conversion system components.

Table 3.4-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.4, that are addressed in the GALL Report.

Table 3.4-1 Staff Evaluation 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, steam line and in auxiliary feedwater (AFW) piping (PWR only) (Item Number 3.4.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system) (Item Number 3.4.1.2)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL which recommends further evaluation (See Section 3.4.2.2.2)
External surface of carbon steel components (Item Number 3.4.1.5)	Loss of material due to general corrosion	Plant-specific	Systems Monitoring Program	See Section 3.4.2.2.4

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Carbon steel piping and valve bodies (Item Number 3.4.1.6)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion Program	Flow-Accelerated Corrosion Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)
Carbon steel piping and valve bodies to main steam system (Item Number 3.4.1.7)	Loss of material due to pitting and crevice corrosion	Chemistry Control Program	Chemistry Control Program	Consistent with GALL, with exceptions, 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 Program	Bolting Integrity Program	Consistent with GALL with exceptions, which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/condensers serviced 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, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System Program	Open-Cycle Cooling Water System Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/condensers serviced 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 Program	Closed-Cycle Cooling Water System Program	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 Program	Aboveground Carbon Steel Tanks Program	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
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; MIC	Buried piping and tanks surveillance Buried piping and tanks inspection	N/A	Not applicable At BFN, the condensate storage tanks and piping and fittings associated with the condensate storage tank are not located underground

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.4.2.1, involves 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 SER Section 3.4.2.2, involves the staff's review of the AMR results for components in the steam and power conversion systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, 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, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.4.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the steam and power conversion system components:

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program
- Bolting Integrity Program
- BWR stress corrosion cracking program
- Chemistry Control Program
- Compressed Air Monitoring Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Aboveground Carbon Steel Tanks Program
- Selective Leaching of Materials Program
- Buried Piping and Tanks Inspection Program

Staff Evaluation. In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant provided a summary of AMRs for the steam and power conversion 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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 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 had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated 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 was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review 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 had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its audit to determine whether the applicant's reference to the GALL Report in the LRA is acceptable.

The staff reviewed the LRA to confirm that the applicant had (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects are reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the steam and power conversion system components that are subject to an AMR.

On the basis of its audit, the staff determined that for AMRs not requiring further evaluation, as identified in LRA Table 3.4.1 (Table 1), the applicant's references to the GALL Report are acceptable, and no further staff review is required.

Conclusion. The staff evaluated 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 concluded 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 concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.4.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the steam and power conversion system. For some line items consistent with the GALL Report in LRA Tables 3.4.2-1 through 3.4.2-7 (LRA Table 2 in each section), 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
- quality assurance for aging management of NSR components

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 audited and reviewed the applicant's evaluation to determine whether it had adequately addressed the issues that the applicant further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.4.2.2. Details of the staff's audit are documented in the staff's audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.3.2.2.3, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

3.4.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

The staff reviewed the LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.

SRP-LR Section 3.4.2.2.2 states that loss of material due to general, pitting, and crevice corrosion should be evaluated further 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 that loss of material due to pitting and crevice corrosion should be evaluated further for stainless steel tanks and heat exchanger/cooler tubes. The Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines in BWRVIP-79 (EPRI TR-103515) for water chemistry in BWRs; however, corrosion may occur at locations of stagnant flow conditions. Therefore, the effectiveness of the Chemistry Control Program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the components' intended function will be maintained during the period of extended operation. The AMP recommended by the GALL Report is XI.M32, "One-Time Inspection."

In LRA Section 3.4.2.2.2, the applicant credits the Chemistry Control Program to manage loss of material for the components requiring further evaluation. The applicant addressed the GALL Report recommendation for further evaluation to verify the effectiveness of the chemistry control through the One-Time Inspection Program. The staff reviewed the Chemical Instruction (CI) 13.1, Chemistry Program, Revision 20, which implements chemistry control of primary water used in the steam and power conversion system. The implementing procedure recommends that the effectiveness of the Chemistry Control Program should be verified by means of tools like plant action levels at cut-off points established for contaminant concentrations recommended by Industry guidance to ensure that corrosion is not occurring, with corrective actions if these are exceeded. The staff did not find any instances of exceeding action level II or III in the past five years of operation (i.e., levels exceeding O_2 > 100 ppb or chlorides > 150 ppb or sulfates > 150 ppb). The staff concluded that the applicant had satisfactorily complied with GALL recommendations in managing this aging effect and demonstrated that the effects of aging for loss of material will be adequately managed 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).

3.4.2.2.3 Loss of Material due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.4.2.2.4 General Corrosion

The staff reviewed the LRA Section 3.4.2.2.4 against the criteria in SRP-LR Section 3.4.2.2.4.

SRP-LR Section 3.4.2.2.4 states that loss of material due to general corrosion could occur on the external surfaces of all carbon steel SCs, including closure bolting exposed to operating temperature less than 212 °F. The GALL Report recommends further plant-specific evaluation to ensure that this aging effect is adequately managed.

In LRA Section 3.4.2.2.4, the applicant stated that it will implement the Systems Monitoring Program to manage general corrosion of external surfaces exposed to operating temperatures less than 212 °F.

The applicant credits the Systems Monitoring Program to manage general corrosion of external surfaces exposed to operating temperatures less than 212 °F. This is consistent with the GALL Report. The staff accepted the Systems Monitoring Program, and its evaluation of this program is documented in SER Section 3.0.3.3.1.

The staff found that the applicant demonstrated that the effects of aging for loss of material will be adequately managed 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).

3.4.2.2.5 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.4.2.2.6 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 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 claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determines that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had 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).

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.4.2.1 through 3.4.2.7, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report. The components impacted by the AMRs are from the following steam and power conversion systems:

- Table 3.4.2.1: Main Steam System (001)
- Table 3.4.2.2: Condensate and Demineralized Water System (002)
- Table 3.4.2.3: Feedwater System (003)
- Table 3.4.2.4: Heater Drains and Vents System (006)
- Table 3.4.2.5: Turbine Drains and Miscellaneous Piping System (008)
- Table 3.4.2.6: Condenser Circulating Water System (027)
- Table 3.4.2.7: Gland Seal Water System (037)

In LRA Tables 3.4.2.1 through 3.4.2.7, the applicant indicated, via Notes F through J, that combinations of component type, material, environment, and AERM do not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item 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 had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

In RAI 3.4-1, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1 through 3.4.2.7, carbon and low-alloy steel bolting in an inside air (external) or outside air (external) environment is not identified with the aging effect of cracking requiring management. In RAI 3.4-1, dated November 18, 2004, the staff requested the applicant to discuss the specific material grading used for the bolting in each of the associated systems, and justify the basis for concluding that crack initiation/growth due to SCC is not a concern for the bolting during the period of extended operation. In its response, by letter dated December 16, 2004, the applicant stated that the cracking aging effect is not identified because high-yield bolting materials (yield strength above 150 ksi) had not been identified and a review of the BFN operating experience had not identified any instances where mechanical component failure was attributable to SCC of high-strength bolting. In addition, the use of molybdenum disulfide thread lubricant, which is considered to promote SCC, is not allowed by site and engineering procedures. Therefore, loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and no aging management is required for the period of extended operation.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-1 is resolved.

In RAI 3.4-2, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.2, 3.4.2.3, 3.4.2.6, and 3.4.2.7, copper-alloy components in an inside air (external) environment are not identified with any aging effects requiring management. Therefore, the staff requested the applicant to provide a discussion of the air environment involved, and to justify the basis for concluding that there are no aging effects requiring management under the material/environment combinations. The staff also requested the applicant to provide a summary description of the stated industry guidance. In its response, by letter dated December 16, 2004, the applicant stated that the copper-alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation or periodic wetting could occur. Copper-alloy components containing fluid at a temperature below the dew point of the external environment is subject to condensation. The identified aging effects/mechanisms were then determined based on the particular copper alloy present and whether condensation or periodic wetting could occur. Based on this evaluation, the applicant concluded that there were no instances where copper-alloy components with greater than 15 percent zinc were subject to an aggressive environment or condensation/periodic wetting. Therefore, no aging effects that require management during the period of extended operation were identified for the copper-alloy components in the subject tables. The applicant also provided a summary description of the industry guidance (i.e., EPRI Technical Report 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools"), which supports the above finding for copper alloy.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-2 is resolved.

In RAI 3.4-3, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1, 3.4.2.3, 3.4.2.4, and 3.4.2.5, carbon and low-alloy steel bolting in an inside air (external) environment is not identified with any aging effects requiring management. Also, the applicant indicated that carbon and low-alloy steels are not susceptible to external general corrosion when the temperature is greater than 212 °F. Therefore, the staff requested the applicant to discuss the specific temperature environment for bolting, instead of piping, and to justify the basis for concluding that no aging effects need to be identified for the bolting.

In its response, by letter dated December 16, 2004, the applicant stated that LRA Table 3.4.2.1 for the main steam system, LRA Table 3.4.2.3 for the feedwater system, LRA Table 3.4.2.4 for the heater drain and vents system, and LRA Table 3.4.2.5 for the turbine drains and miscellaneous piping system do not identify general corrosion as an aging effect for carbon and low-alloy steel bolting in an inside air (external) environment as this bolting is maintained dry by the heat to which it is exposed. The applicant stated that during normal operations the internal environment for those portions of the above systems within the scope of license renewal is much higher than 212 °F (>300 °F). Since the bolting connections are constantly in contact with the high temperature components within these systems, the bolting itself within these systems will experience temperatures higher than 212°F. Carbon and low-alloy steels are not susceptible to external general corrosion at temperatures above 212°F.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-3 is resolved.

In RAI 3.4-4, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.3, carbon and low-alloy steel components in air/gas (internal) - moist air environments are identified as being susceptible to loss of material due to crevice, galvanic, general, and pitting corrosion. In lieu of a periodic inspection program, the One-Time Inspection Program is credited as the only applicable AMP. In LRA Table 3.4.2.6, carbon and low-alloy steel and cast iron and cast iron-alloy components in raw water (internal) environments are identified as being susceptible to loss of material due to biofouling, MIC, crevice, general, and pitting corrosion. The One-Time Inspection Program is credited as the only applicable AMP. Therefore, the staff requested the applicant to provide justification that the One-Time Inspection program, instead of the Periodic Inspection Program, should be used to manage the aging effects for the above components and material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that the carbon and low-alloy steel components in LRA Table 3.4.2.3 for the feedwater system are exposed to an air/gas--moist air environment in two applications. The first application is the small segment between the dual isolation valves on system vents and drains, and the second application is valve packing leakoff lines on Unit 1 feedwater isolation valves. These leakoff lines will be removed prior to Unit 1 restart, and will not be applicable to the LRA.

The small segment of piping/fittings between the dual isolation valves on system vents and drains is exposed to feedwater quality water when the valves are open to support maintenance activities and has trapped air with varying amount of feedwater, based on how the valves are closed (i.e., the sequence and time between valve closings). The applicant stated that the safety consequences for this short segment of piping failing are minimal as this line is downstream of a closed isolation valve that is manually opened only to support maintenance activities. Minimal degradation is expected based on the quality of the water potentially in these components. For completeness, however, and using the One-Time Inspection Program the applicant will perform inspections to verify that these lines are not degrading. Based on the expected minimal degradation as stated in the above, the staff considered the applicant's proposed use of the One-Time Inspection Program to be acceptable.

In LRA Table 3.4.2.6, for the condenser circulating water system, carbon and low-alloy steel and cast iron and cast iron-alloy components in raw water (internal) environments are identified as being susceptible to loss of material due to biofouling, MIC, crevice, general, and pitting corrosion. The in-scope components in the condenser circulating water system are those components that provide the anti-siphon vacuum breaker function. The applicant stated that upon re-reviewing the license renewal scope for the condenser circulating water system, it was determined that raw water was inadvertently specified as the internal environment for the anti-siphon vacuum breaker components. The applicable internal environment (air/gas) has already been evaluated for this system and is included in the LRA. The raw water environment will be deleted from this system.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-4 is resolved.

In RAI 3.4-5, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1 and 3.4.2.3, bolting made of carbon and low-alloy steel, nickel alloy, and stainless steel in inside air (external) environments are identified as being susceptible to loss of bolting function due to wear. The Bolting Integrity Program is credited as the AMP. The staff noted that LRA Section B.2.1.16 does not specifically address "loss of bolting function" due to wear as an aging effect to be managed by the AMP. Therefore, the staff requested the applicant to discuss how the identified aging effect will be managed by the program.

In its response, by letter dated December 16, 2004, the applicant stated that bolting degradation due to wear (fretting) could occur at locations of repeated relative motion of mechanical component bolted joints. Wear of bolted joint components is generally not a concern; however, for license renewal purposes, wear is being assumed as a potential mechanism for "critical bolting applications." "Critical bolting applications" constitute reactor coolant pressure boundary components where closure bolting failure could result in loss of reactor coolant and jeopardize safe operation of the plant. Loss of material function due to wear is managed by the Bolting Integrity Program. This program specifies inspection requirements in accordance with ASME Code Section XI and recommendations of EPRI NP-5769. These inspection requirements include visual inspections looking for wear as well as for cracks, corrosion, and physical damage on the surface.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-5 is resolved.

In RAI 3.4-6, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, aluminum-alloy fittings and piping in a treated-water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice, galvanic, and pitting corrosion. Therefore, the staff requested the applicant to explain (1) why loss of material due to general corrosion is not identified as a potential AERM, (2) why FAC is not a concern for the portion of the condensate system that contains single phase fluid with temperatures less than 200 °F, and (3) how the Chemistry Control Program is used to manage the aging effects of the components/material/environment combinations identified above.

In its response, by letter dated December 16, 2004, the applicant stated that as per industry guidance, aluminum and aluminum-based alloys are not susceptible to loss of material due to general corrosion. The applicant also stated that FAC is only associated with carbon and low-alloy steels; therefore, it would not be identified as an aging mechanism for the aluminum-alloy components. Also, the portions of the condensate system that are within the license renewal boundary are the supply lines to the emergency core cooling pumps. These lines contain single phase fluid with temperatures significantly less than 200 °F with only periodic flow. Consequently, erosion/corrosion is not an aging mechanism that must be managed for the period of extended operation in the condensate system.

The applicant stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated-water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The One-Time Inspection Program is used to verify the Chemistry Control Program's effectiveness.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-6 is resolved.

In RAI 3.4-7, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, polymer fittings in an inside air (external) or treated-water (internal) environment are not identified with any aging effects. Therefore, the staff requested the applicant to provide a discussion of the air and treated-water environments involved and justify the basis for concluding that there are no aging effects requiring management under such material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that polymer fittings in LRA Table 3.4.2.2 within the condensate system are the insulation couplings between carbon steel and stainless steel pipe, and between aluminum and stainless steel pipe. Acetal (the generic name for a family of polymer products that includes DELRIN) provides high strength and stiffness along with increased dimensional stability and ease of machining. The applicant stated that a review of available industry information did not identify any aging effects for DELRIN that would be attributable to the treated-water (internal) environment or the inside air (external) environment.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-7 is resolved.

In RAI 3.4-8, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, aluminum-alloy fittings in a treated-water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Therefore, the staff requested the applicant to explain why loss of material due to general and galvanic corrosion is not identified as a potential AERM during the period of extended operation. The staff also requested the applicant to explain how the Chemistry Control Program, with the association of One-Time Inspection Program, is used to manage the identified aging effects.

In its response, by letter dated December 16, 2004, the applicant stated that as per industry guidance, aluminum and aluminum-based alloys in a treated-water environment are not susceptible to loss of material due to general corrosion. In addition, the applicant stated that the aluminum valves listed in LRA Table 3.4.2.2 as being within the condensate system are not in contact with more cathodic materials. Therefore, galvanic corrosion is not a concern for aluminum valves in a treated-water environment for the condensate system.

The applicant also stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated-water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The One-Time Inspection program is used to verify the Chemistry Control Program's effectiveness as recommended by the GALL Report.

After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR Supplement contains an adequate description of the program.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-8 is resolved.

In RAI 3.4-9, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.3, stainless steel fittings, piping, valves, and restricting orifices forming the reactor coolant pressure boundary (RCPB) in an air/gas (internal), moist air environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Also, CASS valves in an RCPB in an air/gas (internal), moist air environment are identified as susceptible to change in material properties/reduction in fracture toughness due to thermal aging. The One-Time Inspection Program is credited to manage the identified aging effects. Therefore, the staff requested the applicant to provide justification that the One-Time Inspection Program alone, in lieu of a more appropriate periodic inspection program, should be used to manage the identified aging effects for the above-mentioned components and material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that the stainless steel reactor coolant pressure boundary components in Table 3.4.2.3, for the feedwater system, are exposed to an air/gas environment when air is trapped in the vessel flange leak detection line when the vessel head is secured. The air/gas environment is considered moist air because the trapped air is not dried and there is a small potential for leakage. The aging effects are conservatively identified as a moist air environment.

The applicant stated that fittings are addressed in rows 19 and 20 of LRA Table 3.4.2.3. The AMPs identified for cracking are the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and the One-Time Inspection Program. The applicant stated that these same aging effects and AMPs should be shown for each applicable component (i.e., piping in rows 40 and 41, and restricting orifices in line item 46). Because of that, line item 46 in the table should be replaced by two line items with aging effects/mechanisms and AMPs similar to those in rows 40 and 41. Valves are addressed in rows 68 and 69. The BWR Stress Corrosion Cracking Program, instead of the One-Time Inspection Program, is the appropriate AMP for the cracking aging effect of stainless steel RCPB valves in line item 68, which should be corrected accordingly. For the cracking aging effect for piping components less than 4 inches NPS, GALL Report Item IV.C1.1-I states, "a plant-specific destructive examination or a nondestructive examination (NDE) that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the extended period of operation." The applicant has included this small bore piping inspection in the One-Time Inspection Program.

For loss of material due to crevice and pitting corrosion, the One-Time Inspection Program is credited as an AMP because corrosion is not expected to occur for the stainless steel components in an air/gas (internal) with moist air environment. The piping is not subject to condensation and is dry except for the abnormal case when reactor vessel flange leakage occurs. The applicant stated that any water that is introduced to this line is reactor grade treated water and, as such, has minimal potential for corrosion.

The applicant stated that thermal aging of CASS valves is addressed in line item 67, where an incorrect AMP was identified. The correct AMP is the ASME Section XI Subsection IWB, IWC, and IWD Inservice Inspection Program. Therefore, line item 67 should be corrected accordingly.

Based on the above updated information, the staff considered that the applicant had adequately addressed its concern regarding the use of the One-Time Inspection Program as the sole AMP for the identified aging effects. Therefore, the staff's concern described in RAI 3.4-9 is resolved.

3.4.2.3.1 Main Steam System – Summary of Aging Management Evaluation – Table 3.4.2.1

The staff reviewed LRA Table 3.4.2.1, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2.1, the applicant identified no aging effects for stainless steel and carbon and low-alloy steel components exposed to air, for piping and tubing component types. Air is not identified in the GALL Report 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 being referred to are typical of ambient air (e.g., under a shelter, indoor, or air-conditioned enclosure or room). Therefore, the staff concluded that there are no aging effects requiring management for stainless steel in an air environment.

In LRA Table 3.4.2.1, the applicant identified no aging effects for carbon and low-alloy steel condenser components. No aging effects were identified by the AMR for the main condenser components made of carbon steel, or stainless steel in a treated-water environment or inside air. These materials have successfully performed as main condenser materials at other plants. Further, the applicant concluded that aging management of the main condenser is not required based on analysis of materials, environments, and aging effects. Condenser integrity required to perform the post-accident intended function (holdup and plateout of main steam isolation valve (MSIV) leakage) is continuously confirmed by normal plant operation. The main condenser must perform a significant pressure boundary function (maintain vacuum) to allow continued plant operation. For these reasons, the applicant has not identified any applicable aging effects for the main condenser. The staff concurred with the applicant's conclusion because the main condenser integrity is continuously confirmed during normal plant operation and, thus, the condenser post-accident function will be ensured.

3.4.2.3.2 Condensate and Demineralized Water System – Summary of Aging Management Evaluation – Table 3.4.2.2

The staff reviewed LRA Table 3.4.2.2, which summarizes the results of AMR evaluations for the condensate and demineralized water system component groups.

In LRA Table 3.4.2.2, the applicant identified no aging effects for stainless, carbon, and low-alloy steel components exposed to air for piping and tubing component types. Air is not identified in the GALL Report 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. Therefore, the staff concluded that there are no AERMS for stainless, carbon, and low-alloy steel in an air environment.

In LRA Table 3.4.2.2, the applicant identified an aging effect of galvanic corrosion for carbon and low-alloy steel components exposed to treated water internally. The GALL Report does not indicate the aging effect, but recommends further evaluation for these components.

In managing the galvanic aging effect, the applicant stated that galvanic corrosion can only progress if the dissimilar metals are in contact in the presence of an electrolyte. Control of galvanic corrosion in treated water systems is possible by maintaining adequate chemistry controls. As treated water is a poor electrolyte, the dissimilar metals in this environment would experience little or no galvanic corrosion. This is evidenced by the lack of industry operating experience of galvanic corrosion failures in treated water systems. A review of BFN PERs and work orders did not identify instances where galvanic corrosion was a failure mechanism.

The staff found that the applicant demonstrated that the effects of aging for loss of material due to galvanic corrosion will be adequately managed 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).

In LRA Table 3.4.2.2, aluminum-alloy fittings in a treated-water environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice, galvanic, and pitting corrosion. Since this material was not listed in the GALL Report, the staff needed some additional explanation to justify the Chemistry Control Program and One-Time Inspection Program to manage the effect.

The applicant stated that the aging effects identified for aluminum alloys are consistent with EPRI Report 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3." Aluminum alloys were evaluated using the guidelines given in the report. BFN utilizes the Chemistry Control Program and One-Time Inspection Program to manage the effect, which is also the industry standard; based on past precedents review of similar applications for managing the aging effects of aluminum alloys in treated-water environments, the staff found the response acceptable.

In LRA Table 3.4.2.2, for carbon and low-alloy steel piping in air/gas environment (internal) the applicant mentions only one-time inspection for aging management due to general corrosion.

GALL Table VIII.E.1, Condensate System, does not address the air/gas environment identified in the LRA.

The applicant clarified that the row 35 environment in LRA Table 3.4.2.2 referred to the area between the two isolation valves on condensate system vents and drains. This small segment of piping is exposed to condensate flow when the valves are open and has air trapped with varying amount of condensate based on how the valves are closed, that is, the sequence and time between valve closings. The safety consequences for this short segment of piping failing are non-existent, because this line is downstream of a closed isolation valve. However, for completeness and to verify that these lines are not degrading, the applicant will perform some inspections using the One-Time Inspection Program, even though the GALL Report does not address the air/gas environment.

3.4.2.3.3 Feedwater System – Summary of Aging Management Evaluation – Table 3.4.2.3

The staff reviewed LRA Table 3.4.2.3, which summarizes the results of AMR evaluations for the feedwater system component groups.

In LRA Table 3.4.2.3, stainless steel fittings (item 11) in a treated water environment are identified as being susceptible to crack initiation and SCC, which is not identified in GALL Report (VIIID2.1.1-b) for this item.

The applicant stated in Mechanical Evaluation Report - Feedwater System 003 that the shape of components in this system made from stainless steel material may present a high stress environment, and the treated water may contain contaminants such as chlorides and sulfides. This combination, with temperatures above 140 °F, may promote SCC. This conclusion is supported by evidence from industry experience. The staff concurred with the applicant that this aging effect needed appropriate evaluation and managing. The staff agreed that the proposed management through the Chemistry Control Program and One-Time Inspection Program will be adequate to manage the aging.

3.4.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the steam and power conversion system, as required by 10 CFR 54.21(d).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports components and component groups associated with the following systems:

- primary containment structures
- reactor buildings
- equipment access lock
- diesel generator buildings
- standby gas treatment building
- off-gas treatment building
- vacuum pipe building
- residual heat removal service water tunnels
- electrical cable tunnel from intake pumping station to the powerhouse
- underground concrete encased structures
- earth berm
- intake pumping station
- gate structure No. 3
- intake channel
- north bank of cool water channel east of gate structure No. 2
- south dike of cool water channel between gate structure Nos. 2 and 3
- condensate water storage tanks' foundations and trenches
- containment atmosphere dilution storage tanks' foundations
- reinforced concrete chimney
- turbine buildings
- diesel high-pressure fire pump house
- vent vaults
- transformer yard
- 161 kV (kiloVolt) switchyard
- 500 kV switchyard
- structures and component supports commodities group

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant provided AMR results for components. In LRA Table 3.5.1, "Summary of Aging Management Evaluations for Structures and Component Supports Evaluated in Chapter II and III of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the containments, structures, and component supports components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of the AERM. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify the AERM. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the containments, structures, and component supports components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

During the weeks of June 21 and July 26, 2004, the staff performed an onsite audit, of AMRs to confirm the applicant's claim that certain identified AMRs are consistent with the GALL matters described in the GALL Report. The staff verified that the material presented in the LRA is applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.5.2.2, dated July 2001. The staff's audit evaluations are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed are appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.5.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the containments, structures, and component supports components.

Table 3.5-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Containments, Structures, and Component Supports 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	Cumulative fatigue damage	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1.2)	Cracking due to cyclic loading, crack initiation and growth due to SCC	Containment Inservice Inspection (ISI) Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
Penetration sleeves, penetration bellows, and dissimilar metal welds (Item Number 3.5.1.3)	Loss of material due to corrosion	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	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 Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
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 Program; Plant Technical Specifications Program	Containment Leak Rate Test Program; Plant Technical Specifications Program	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 Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	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 Program	N/A	Not applicable BFN has a Mark I steel containment
Concrete elements: foundation (Item Number 3.5.1.8)	Cracks, distortion, and increases in components stress level due to settlement	Structures Monitoring Program	N/A	Not applicable BFN has a Mark I steel containment

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Concrete elements: foundation (Item Number 3.5.1.9)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring Program	N/A	Not applicable BFN has a Mark I steel containment
Concrete elements: foundation, dome, and wall (Item Number 3.5.1.10)	Reduction of strength and modulus due to elevated temperature)	Plant-specific	N/A	Not applicable BFN has a Mark I steel containment
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)	TLAA	Not applicable BFN has a Mark I steel containment and not prestressed concrete with tendons
Steel elements: liner plate, containment shell (Item Number 3.5.1.12)	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL which recommends further evaluation (See Section 3.5.2.1)
Steel elements: vent header, drywell head, torus, downcomers, and pool sheel (Item Number 3.5.1.13)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue
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 Program	N/A	Not applicable BFN does not credit coatings to prevent general corrosion
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 Program	N/A	Not applicable BFN has a Mark I steel containment and not prestressed concrete with tendons
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 Program	N/A	Not applicable BFN has a Mark I steel containment

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel elements: vent line bellows, vent headers, and downcomers (Item Number 3.5.1.17)	Cracking due to cyclic loads; crack initiation and growth due to SCC	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends further evaluation (See 3.5.2.1)
Steel elements: suppression chamber liner (Item Number 3.5.1.18)	Crack initiation and growth due to SCC	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
Steel elements: drywell head and downcomer pipes (Item Number 3.5.1.19)	Fretting and lock up due to wear	Containment ISI Program	Containment ISI Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
All Groups except Group 6: accessible interior/exterior concrete and steel components (Item Number 3.5.1.20)	All types of aging effects	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 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, and corrosion of embedded steel	Plant-specific		Consistent with GALL, which recommends further evaluation if an aggressive below-grade environment exists (See Section 3.5.2.2.1)
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; FERC/US Army Corps of Engineers Dam Inspection and Maintenance Program	Inspection of Water-Control Structures; FERC/US Army Corps of Engineers Dam Inspection and Maintenance Program	Consistent with GALL which recommends further evaluation (See Section 3.5.2.2.8)
Group 5: liners (Item Number 3.5.1.23)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Chemistry Control Program; Monitoring of Spent Fuel Pool Water Level Program	Chemistry Control Program; Monitoring of Spent Fuel Pool Water Level Program	Consistent with GALL, with exceptions, 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
Groups 1-3, 5, 6: all masonry block walls (Item Number 3.5.1.24)	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall Program	Masonry Wall Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 7-9: foundation (Item Number 3.5.1.25)	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.2)
Groups 1-3, 5-9: foundation (Item Number 3.5.1.26)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring Program	N/A	Not applicable BFN does not use porous concrete subfoundations
Groups 1-5: concrete (Item Number 3.5.1.27)	Reduction of strength and modulus due to elevated temperature	Plant-specific	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.3)
Groups 4, 8: liners (Item Number 3.5.1.28)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Plant-specific	N/A	Not applicable BFN does not have any Group 7 structues BFN does not have in-scope stainless steel liners in an exposed-to-fluid environment for any Group 8 structure
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 Program	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation if within the scope of the applicant's Structures Monitoring Program (See Section 3.5.2.1)
Groups 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	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups 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 Program	ISI Program	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 Program		Exception to GALL (See Section 3.5.2.3.26)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.5.2.1, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.5.2.2, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the containments, structures, and component supports components is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

<u>Summary of Technical Information in the Application</u>. In LRA Section 3.5.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the containments, structures, and component supports components:

- 10 CFR 50 Appendix J Program
- ASME Section XI Subsection IWE Program
- Structures Monitoring Program
- Chemistry Control Program
- Fire Protection Program
- Masonry Wall Program
- Inspection of Water-Control Structures Program
- ASME Section XI Subsection IWF Program
- One-Time Inspection Program

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 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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 had not been able to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. 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 indicated 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, as documented in the BFN audit and review 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 had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its review and audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff determined that the applicant had: (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the SCs that are subject to an AMR. The staff also determined that the LRA line item is consistent with the GALL Report Volume 2 system tables line item for component type and MEAP.

To confirm consistency with the GALL Report, during the onsite audit in the weeks of June 21 and July 26, 2004, the staff requested the applicant to clarify the following LRA line items:

In LRA Table 3.5.2.1, the applicant credits the 10 CFR Part 50, Appendix J Program for some structures and component supports in the primary containment. The GALL Report is also based on an expectation that plant technical specifications will be credited. The staff requested the applicant to identify these items and explain the BFN plant technical specifications that govern the leakage testing of these items after each opening.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1, rows 4 and 6 apply to the drywell personnel access airlock. Table 3.5.2.1, rows 8 and 10, apply to the torus and drywell access hatches and equipment hatches. These containment pressure boundary components will continue to be inspected consistent with the CLB Technical Specifications for Appendix J requirements. BFN Technical Specification Requirements, Section 5.5.12, "Primary Containment Leakage Rate Testing Program," provides the requirement to establish a program to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, and provides the leakage rate acceptance criteria of the program. With these clarifications, the staff concluded that these items are consistent with the GALL Report.

In reference to LRA Table 3.5.2.1, the staff further requested the applicant to identify the caulking and sealants included under this item and clarify why Appendix J is not a credited AMP. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1 applies to the moisture barrier seal between the drywell steel shell and the concrete floor in the bottom of the drywell, elevation 549.92 feet. Appendix J testing is not required, since the drywell floor moisture barrier seal between drywell steel shell and the 549.92-foot elevation concrete does not have a pressure boundary function. The staff concurred with the applicant's explanation and found this acceptable.

In LRA Table 3.5.2.2, the staff observed that the AMP referenced for spent fuel pool liners is not consistent with GALL Report Item III.A5.2-b. The Chemistry Control Program is referenced. However, the GALL Report also includes "monitoring of the spent fuel pool level." The staff requested that the applicant provide the technical basis for this omission. By letter dated

October 8, 2004, the applicant submitted its formal response to the staff, stating that the AMP section for LRA Table 3.5.2.2 should have identified that the spent fuel pool level is monitored by plant operations. Browns Ferry will submit a change to correct this omission. With this correction, the staff concluded that the applicant's AMR is consistent with the GALL Report.

In reference to LRA Table 3.5.2.2, the staff also requested the applicant to describe the AMR for Boral and to clarify whether stainless steel components are used to support the Boral. If the AMR supports the conclusion that Boral does not require aging management, but the stainless steel supports do, then the Chemistry Control Program would be an acceptable AMP for this item. If not, the applicant was requested to provide the technical basis for crediting the Chemistry Control Program as the appropriate AMP for Boral.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Boral core is made up of a central segment of a dispersion of boron carbide in aluminum. This central segment is clad on both sides with aluminum to form a plate. The Boral plates are sandwiched between two stainless steel plates which are closure-welded form the container. Vent holes have been added to prevent the buildup of hydrogen gas between the stainless steel containers. If the stainless steel containers remain intact, the Boral core will be unaffected and will retain its neutron-absorbing capacity. The Chemistry Control Program will manage aging of the stainless steel containers. With these clarifications, the staff concluded that this item is consistent with the GALL Report.

In reference to LRA Tables 3.5.2.12, 3.5.2.13, and 3.5.2.26, the staff requested that the applicant identify each of the components included and explain the reference to Note C (Component is different from, but consistent with, GALL Report item for material, environment, and aging effect. The AMP is consistent with the GALL Report).

In its response, by letter dated October 8, 2004, the applicant stated that Table 3.5.2.1.12, rows 41 and 42, apply to security barrier steel framing at the intake pumping station. Note C was used because the security barrier steel framing was evaluated with structural steel beams columns, and trusses (steel components) commodity group. Table 3.5.2.13, rows 4, 5, 6, 7, and 8, apply to concrete that is sandwiched between the steel sheet pile cells of Gate Structure Number 3. Note C was used because the concrete sandwiched between the steel sheet pile cells was evaluated with concrete elements that were not sandwiched between steel sheet piles. Table 3.5.2.26, rows 19 and 20, apply to cable trays and supports in containment atmosphere and inside air environments. Note C was used because cable trays were evaluated with the cable tray supports. With these clarifications, the staff concluded that these items are consistent with the GALL Report.

In reference to LRA Table 3.5.2.12, the staff requested the applicant to explain the extent to which the referenced submerged structures are inspected for the effects of freeze-thaw under the Inspection of Water-Control Structures Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the referenced submerged structure will be inspected for the effects of freeze-thaw at the waterline where icing conditions could occur. The staff concluded that the applicant's approach to the management of this aging effect is consistent with the GALL Report.

On the basis of its audit, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1 (Table 1), the applicant's references to the GALL Report are acceptable, that the line items are consistent with the GALL Report, and no further staff review is required.

Conclusion. The staff evaluated 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 concluded that the AMR results, that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.5.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the containments, structures, and component supports. The applicant provided information concerning how it will manage the following aging effects:

- aging of inaccessible concrete areas
- cracking, distortion, and increase in component stress level due to settlement; reduction of foundation strength due to erosion of porous concrete subfoundations, if not covered by Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to corrosion in inaccessible areas of steel containment shell or liner plate
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to cyclic loading and stress corrosion cracking
- aging of structures not covered by Structures Monitoring Program
- aging management of inaccessible areas
- aging of supports not covered by Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading
- quality assurance for aging management of non-safety-related components

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 audited and reviewed the applicant's evaluation to determine whether it had adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.5.2.2.1 Aging of Inaccessible Concrete Areas

The discussion in SRP-LR Section 3.5.2.2.1.1 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.2 Cracking, Distortion, and Increase in Component Stress Level Due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program

The discussion in SRP-LR Section 3.5.2.2.1.2 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.3 Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

The discussion in SRP-LR Section 3.5.2.2.1.3 is not applicable to BFN since BFN is a BWR with a Mark steel containment.

3.5.2.2.4 Loss of Material due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate

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 loss of material due to corrosion in inaccessible areas of steel containment elements.

SRP-LR Section 3.5.2.2.1.4 states that 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 and BWR 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: (1) concrete meeting the requirements of ACI 318 or 349 and the guidance of 201.2R was used for the containment concrete in contact with the embedded containment shell or liner; (2) 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; (3) 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 IWE requirements; (4) 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 loss of material due to corrosion in inaccessible areas of steel containment elements is not significant. The drywell steel containment vessel is inaccessible (except for the drywell head) for visual examination from the outside surface. There has been evidence of water leaking from the sand bed drains on both Units 2 and 3. Since there is a horizontal weld connecting the first and second course of drywell liner plates approximately eight inches above the drywell concrete floor, ultrasonic testing (UT) thickness measurements from the drywell floor up to this weld, around the drywell circumference, would conservatively bound the sand pocket area. UT thickness measurements of this area were obtained during the U2C10 and U3C8 refueling outages for Units 2 and 3 respectively and in

1999 and 2002 for Unit 1. The data indicated that the condition of the drywell steel liner plate in this area is good and that this area did not require augmented examination.

The applicant further stated in the LRA that concrete structures and concrete components are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using materials conforming to ACI and ASTM standards. The Structures Monitoring Program monitors the concrete to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell. Research of plant history did not reveal any instances of borated water spills or water ponding on the containment concrete floor. A general visual inspection of the moisture barrier at the junction of the steel drywell shell and the concrete floor is performed once each inspection interval in accordance with the ASME Code Section XI, Subsection IWE Program.

The applicant concluded in the LRA that, since all of the GALL Report further evaluation conditions are satisfied, a plant-specific AMP for corrosion in inaccessible areas (embedded containment steel shell and drywell support skirt) is not required.

During the audit, the staff requested the applicant to provide details of the UT measurements in the sand pocket region for all three units, including comparisons with the original wall thicknesses and trending results. The staff also requested the applicant to discuss future planned inspections of steel containment corrosion in the sand pocket region for all three units and the basis for not inspecting other regions of the drywell for all three units in light of the evidence of water leaking from the sand bed drains. It is noted that there is expansion foam in the air gap between the drywell shell and the surrounding concrete that can become wet as a result of the leaking water. Thus, other areas of the drywell shell could be susceptible to corrosion.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that in response to GL 87-05, which addressed the potential for corrosion of BWR Mark I steel drywells in the “sand pocket region,” it had provided the staff with the results of the ultrasonic testing for corrosion degradation of drywell liner plate on Aug. 30, 1988. The results of the ultrasonic testing show that each unit's drywell had been ultrasonically tested near the sand cushion area during 1987. The tests showed that the nominal thickness was maintained on each drywell. Below, are the results of each unit’s drywell ultrasonic testing. (Note: the following results are quoted from the applicant’s letter to the staff dated August 30, 1988.)

- Unit 1- No reading below the nominal thickness of one inch was measured, indicating that the integrity of the drywell liner plate is maintained. Periodic leakage from the sand cushion area has been observed. Corrosive species in the drainage are bases to suspect a higher rate of corrosion on Unit 1 drywell liner plate than on Unit 2 and 3. However, objective evidence of serious corrosion damage was not noted.
- Unit 2 - No reading below the nominal thickness of one inch was measured, indicating that no damage to the integrity of the drywell liner plate has occurred.
- Unit 3 - No reading below the nominal thickness of one inch was measured, indicating that no damage to the integrity of the drywell liner plate has occurred.

The applicant further stated that Procedure SPP-9.1, “ASME Section XI,” is the applicant’s standard to establish administrative controls and provide requirements, standard methods, guidance, and interfaces for preparation of ASME Code Section XI and augmented inservice inspection and testing programs at each nuclear site. In addition, this procedure allows for the control and dissemination of the site programs as stand alone documents, as it is required to meet the individual site-specific requirements resulting from the physical plant differences. BFN Technical Instruction 0-TI-376, “ASME Section XI Containment Inservice Inspection Program Units 1, 2, and 3,” is an administrative technical instruction employed to implement the inservice inspection provisions of SPP-9.1 relative to Class MC components at BFN. Appendix 9.7 to BFN Technical Instruction 0-TI-376 documents the Units 2 and 3 evaluation of Class MC components to determine augmented examination requirements in accordance with Table IWE-2500-1, Category E-C, Containment Surfaces Requiring Augmented Examination. Included as one of the areas to evaluate for augmented inspections was the “Drywell SCV at the sand bed region.” The evaluation considered the potential degradation mechanisms of each area; the adequacy of existing programs and maintenance practices with respect to the monitoring, prevention, and correction of degradation; and industry experience applicable to the area; and provided a conclusion with respect to augmented examination requirements.

The applicant also stated that the drywell SCV at the sand bed region evaluation summarized the response to GL 87-05 and the need to obtain more data to conclude whether augmented inspections were warranted. UT thickness measurements of this area, in accordance with IWE-2500 (c)(2), (c)(3), and (c)(4), were obtained during the U3C8 and U2C10 refueling outages. The data indicate that the condition of the drywell steel liner plate in this area is good, and that this area should not be categorized for augmented examination for Units 2 and 3.

As part of the re-start activities for Unit 1, the applicant stated that a similar evaluation will be performed to determine if augmented inspections would be required. This evaluation and conclusion will be included in BFN Technical Instruction 0-TI-376 prior to Unit 1 re-start.

In its response, the applicant also noted that aging management of drywell corrosion will be addressed in its response to RAI 3.5-4. This issue is dispositioned in the staff evaluation of the applicant’s response to RAI 3.5-4.

3.5.2.2.5 Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

The discussion in SRP-LR Section 3.5.2.2.1.5 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.6 Cumulative Fatigue Damage

In LRA Section 3.5.2.2.1.6, the applicant stated that fatigue analysis of BWR Mark I and Mark II containment steel elements, penetration sleeves, and penetration bellows are TLAAs as defined in 10 CFR 54.3. The TLAA evaluation of cumulative fatigue damage is addressed in LRA Section 4.6. The staff evaluated TLAAs in SER Section 4.

3.5.2.2.7 Cracking due to Cyclic Loading and Stress Corrosion Cracking

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.

SRP-LR Section 3.5.2.2.1.7 states that cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in all types of containments. Cracking could also occur in vent line bellows, vent headers and downcomers due to SCC for BWR containments. Further evaluation of inspection methods is recommended to detect cracking due to cyclic loading and SCC since visual VT-3 examinations may be unable to detect this aging effect.

Cracking Due to SCC. The GALL AMP XI.S1, “ASME Section XI Subsection IWE,” covers inspection of these items under examination categories E-B, E-F, and E-P (10 CFR Part 50 Appendix J pressure tests). In 10 CFR 50.55a, examination categories E-B and E-F are identified as optional during the current term of operation. For the extended period of 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 the LRA, the applicant stated that SCC of stainless steel exposed to atmospheric conditions and contaminants is considered plausible only if the material temperature is above 140 °F. In general, SCC very rarely occurs in austenitic stainless steels below 140 °F. Although stress corrosion cracking has been observed in systems at temperatures lower than this 140 °F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. This material is at a relatively low temperature, in a sheltered environment, and not exposed to a corrosive environment.

The applicant further stated in the LRA that industry experience, detailed in NRC information notice (IN) 92-20, described instances of the failure of the 10 CFR Part 50 Appendix J local leak rate test (LLRT) to detect cracking in stainless steel containment penetration bellows. The LLRT was inadequate due to the type of penetration bellows utilized at the nuclear power plant that is the subject of the IN. The type of bellows used on the containment penetrations at BFN is not the type described in IN 92-20. The vent line bellows are a single-ply bellows design. Pipe penetration bellows for high-energy lines are two-ply bellows with a mesh. The design of the penetration bellows allows full pressure to be transmitted to all portions of the bellows during Appendix J testing. Containment penetrations bellows are not susceptible to failure of the 10 CFR Part 50 Appendix J LLRT to detect cracking, as described in IN 92-20. A review of the operating history for the past five years did not indicate any failures associated with vent line and penetration bellows. This issue was pursued in staff RAI 3.5-1 (see SER Section 3.5.2.3.1)

The applicant also stated in the LRA that the reinstatement of Examination Categories E-B and E-F would result in hardship or unusual difficulty for BFN without a compensating increase in the level of quality and safety. Therefore, existing requirements for 10 CFR Part 50 Appendix J Program leak rate testing and visual examinations, in accordance with ASME Code Section XI, Subsection IWE, Examination Category E-A, should be adequate to detect cracking due to SCC. The reinstatement of ASME Code Section XI, Subsection IWE, Weld Examination Categories E-B and E-F would not be required. Weld Examination Categories E-B and E-F have been removed from the ASME Code Section XI, 1998 Edition.

During the audit, the staff asked the applicant if there was any operating history at BFN beyond the past five years regarding signs of cracking and/or failures associated with the vent line and penetration bellows. The staff also requested the applicant to discuss the hardship or unusual difficulty for the applicant regarding reinstatement of Examination Categories E-B and E-F.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that during the last nine years there has been no operating experience to indicate that cracking or other aging effects resulted in a loss of intended function of the vent line bellows or penetration bellows.

The applicant further stated that, in accordance with 10 CFR 50.55a, the performance of examinations required by examination categories E-B and E-F are optional and that the staff found no evidence of industry problems with these welds.

The applicant also stated that specific weld locations on the containment would be required to be located and identified on weld maps in order to perform examinations for examination categories E-B and E-F. These weld locations have not been identified for the ASME Code Section XI Subsection IWE ISI Program. The hardship associated with performing the weld examinations associated with examination categories E-B and E-F is attributed to radiation exposure received while performing examinations of welds that have no industry experience of problems. Since specific weld locations have not been identified for the ASME Code Section XI Subsection IWE ISI Program, it is not possible to provide an estimated radiation exposure for performance of the examinations.

The applicant's response also noted that the Summary of SECY-96-080, "Issuance Of Final Amendment To 10 CFR 50.55a To Incorporate By Reference The ASME Boiler And Pressure Vessel Code (ASME Code), Section XI, Division 1, Subsection IWE And Subsection IWL," states the following:

> The third modification, 50.55a(b)(2)(x)(C), makes the Subsection IWE pressure retaining welds and Subsection IWE pressure retaining dissimilar metal welds inspection optional. The staff concluded that requiring these inspections is not appropriate. There is no evidence of problems associated with welds of this type in operating plants. Therefore, the occupational radiation exposure that would be incurred while performing these inspections cannot be justified. It is estimated that the total occupational exposure that would be incurred yearly in the performance of the containment weld inspections would be 440 person-rems.

The staff found the applicant's response to be acceptable.

Cracking Due to Cyclic Loading. Cracking of the containment shell and penetrations due to cyclic loading is a TLAA. The staff evaluated TLAAs in SER Section 4.

3.5.2.2.8 Aging of Structures Not Covered by 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. LRA Section 3.5.2.2.2.1 addresses aging of Class 1 structures not covered by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.2.1 states that the GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the Structures Monitoring Program. This is described in GALL Report Chapter III and includes: (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, 7-9 structures; (2) scaling, cracking, spalling and increases in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5, 7-9 structures; (3) expansion and cracking due to reaction with aggregates for Groups 1-5, 7-9 structures; (4) cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for Groups 1-5, 7-9 structures; (5) cracks, distortion, and increase in component stress level due to settlement for Groups 1-3, 5, 7-9 structures; (6) reduction of foundation strength due to erosion of porous concrete subfoundations for Groups 1-3, 5-9 structures; (7) loss of material due to corrosion of structural steel components for Groups 1-5, 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 and loss of material due to crevice corrosion of stainless steel liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.2.1 references SRP-LR Subsection 3.5.2.2.1.2 for the technical details of the aging management issue for Items (5) and (6), above, and references SRP-LR Section 3.5.2.2.1.3 for the technical details of the aging management issue for Item (8), above.

In LRA Section 3.5.2.2.2.1, the applicant stated that the further evaluations are also applied to Group 6 structures, when applicable; and that the technical details of the AMRs associated with SRP-LR Section 3.5.2.2.1.2, “Cracking, Distortion, and Increase in Components Stress Level due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program,” and SRP-LR Section 3.5.2.2.1.3, “Reduction of Strength and Modulus of Elasticity due to Elevated Temperature,” are also incorporated in this further evaluation.

The staff’s evaluation for Items (1) through (9) is presented below:

(1) Freeze-thaw

The GALL Report, as updated by ISG-3, recommends that for accessible areas inspections performed in accordance with the Structures Monitoring Program will indicate the presence of loss of material (spalling, scaling) and cracking due to freeze-thaw. For inaccessible areas, evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557). Documented evidence to confirm that the in-place concrete had the air content of three to six percent and that subsequent inspections performed did not detect degradation related to freeze-thaw should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Figure 1.

In LRA Section 3.5.2.2.2.1, the applicant stated that BFN is located in an area with moderate weathering conditions, as noted on Figure 1 of ASTM C33-99. Freeze-thaw is not considered an aging mechanism for concrete components below the frost line. The concrete structures and concrete are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using ingredients conforming to ACI and ASTM standards. TVA specifications require all concrete to contain an air-entraining agent in sufficient quantity to maintain specified percentages based on nominal maximum size aggregate. For severe weather exposures (as defined in TVA-Specifications), the air content identified varies from 4 to 10 percent, depending on aggregate size. Severe weather exposure (as described in TVA-Specifications), is defined as “all exterior surfaces of concrete which will be exposed to alternate wetting and drying.”

The applicant further stated in the LRA that specified air content for reinforced concrete is greater than the three to six percent for air content identified in ISG-03. Therefore, loss of material (spalling, scaling) and cracking due to freeze-thaw are aging effects that require aging management in accordance with ISG-03 for below-grade (above the frost line) reinforced concrete structures and components. Below-grade reinforced concrete will be inspected by the Structures Monitoring Program when excavated for any reason. Accessible exterior above-grade concrete will be monitored by the Structures Monitoring Program to manage loss of material and cracking due to freeze-thaw.

The staff concluded that the applicant's AMR for loss of material and cracking due to freeze-thaw is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(2)(a) Leaching of Calcium Hydroxide

The GALL Report, as updated by ISG-3, recommends that for accessible areas inspections performed in accordance with the Structures Monitoring Program will indicate the presence of increase in porosity and permeability due to leaching of calcium hydroxide. For inaccessible areas, a plant-specific AMP is required for below-grade inaccessible areas (basemat and concrete wall) if the concrete is exposed to flowing water (NUREG-1557). An AMP is not required, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

In LRA Section 3.5.2.2.2.1, the applicant stated that concrete structures and concrete components are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing steel. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77. In addition, concrete components must be exposed to flowing water through the concrete component. Leaching of calcium hydroxide is readily noticeable as white deposits that remain on the concrete surface after a solution of water-free lime from the concrete and carbon dioxide from the air is absorbed and dries. The Structures Monitoring Program inspects concrete areas for signs of leaching. No significant signs of leaching have been documented during these inspection walkdowns. Therefore, the conditions identified in the GALL Report as revised by ISG-03 are satisfied, and aging management of an increase in porosity and permeability and a loss of strength due to leaching of calcium hydroxide for below-grade inaccessible concrete is not required. However, the Structures Monitoring Program will be used to manage aging effects caused by an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide of concrete.

The staff concluded that the applicant's AMR for scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(2)(b) Aggressive Chemical Attack

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections performed in accordance with the Structures Monitoring Program will indicate the presence of increase in porosity and permeability, cracking, or loss of material (spalling, scaling) due to aggressive chemical attack. For inaccessible areas, a plant-specific AMP is required (may be a part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5; chlorides >500 ppm; or sulfates >1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is nonaggressive.

In LRA Section 3.5.2.2.2.1, the applicant stated that the Structures Monitoring Program will be used to inspect accessible concrete areas for aging effects caused by scaling, cracking, spalling and increase in porosity and permeability due to aggressive chemical attack.

The staff concluded that the applicant's AMR for scaling, cracking, spalling and increase in porosity and permeability due to aggressive chemical attack is consistent with the GALL Report for accessible areas, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff's evaluation for inaccessible areas is in SER Section 3.5.2.2.9.

(3) Reaction with Aggregates

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections/evaluations performed in accordance with the Structures Monitoring Program will indicate the presence of expansion and cracking due to reaction with aggregates. For inaccessible areas, evaluation is needed if investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54, ASTM C227-50, or ACI 201.2R-77 (NUREG-1557) demonstrate that the aggregates are reactive.

In LRA 3.5.2.2.2.1, the applicant stated that the aggregate used in the concrete of the BFN components did not come from a region known to yield aggregates suspected of, or known to cause, aggregate reactions. Materials for concrete used in BFN structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. All aggregates used at BFN conform to the requirements of ASTM C33 "Standard Specification of Concrete Aggregates." Appendix XI of ASTM C33 identifies methods for evaluating potential reactivity of aggregates including ASTM C295, ASTM C289, ASTM C227, and ASTM C342. If potentially reactive aggregates were used, then use of a low alkali Portland Cement (ASTM C150 Type II) containing less than 0.60 percent alkali calculated as sodium oxide equivalent was required by TVA-Specifications and will prevent harmful expansion due to alkali aggregate reaction. Therefore, the conditions identified in the GALL Report as revised by ISG-03 are satisfied, and aging management of expansion and cracking due to reaction with aggregates for below-grade inaccessible concrete is not required. However, the Structures Monitoring Program will be used to inspect accessible concrete areas for aging effects caused by reaction with aggregates.

The staff concluded that the applicant's AMR for expansion and cracking due to reaction with aggregates is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(4) Corrosion of embedded steel

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections performed in accordance with the Structures Monitoring Program will indicate the presence of cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. For inaccessible areas, a plant-specific AMP is required (may be a part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5, chlorides > 500ppm, or sulfates > 1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or nonaggressive.

In LRA 3.5.2.2.2.1, the applicant stated that BFN will use the Structures Monitoring Program to inspect accessible concrete areas for aging effects caused by corrosion of embedded steel.

The staff concluded that the applicant's AMR for cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel is consistent with the GALL Report for accessible areas, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff's evaluation for inaccessible areas is in SER Section 3.5.2.2.9.

(5) Settlement

SRP-LR Section 3.5.2.2.2.1 refers to SRP-LR Section 3.5.2.2.1.2 for discussion of settlement. SRP-LR Section 3.5.2.2.1.2 states that cracking, distortion, and increase in component stress level due to settlement could occur in Class I structures. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL Report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL Report recommends no further evaluation if this activity is included in the scope of the applicant's Structures Monitoring Program.

In LRA Section 3.5.2.2.2.1, the applicant stated that cracks, distortion, and increase in component stress level due to settlement are not considered AERM for structures founded on rock or bearing piles. The following BFN structures are founded on rock or bearing piles: reactor buildings, primary containments, intake pumping station, reinforced concrete chimney, off-gas treatment building, equipment access lock, turbine buildings, gate structure number 3, diesel HPFP house, transformer yard, and RHRSW tunnel. Based on industry experience, settlement of Class I structures founded on bedrock or bearing piles have not been noted to cause AERM.

For concrete structures founded on dense soil or backfill, the applicant stated that it can be concluded that cracking due to settlement is not significant if in the past 20 years of operating experience for a structure the total differential settlement experienced is well within the permissible limits for this type of structure and no settlement has manifested itself via cracked walls or cracked foundations. In this case, aging management for settlement would not be applicable for the structure during the period of extended operation. Prior settlement monitoring programs have revealed that soil settlement has stabilized and the structures will continue to perform their intended functions. However, due to prior operating history of settlement in the 1980s at BFN, cracking and distortion due to settlement of structures founded on soil or backfill will be monitored by the Structures Monitoring Program.

The staff concluded that the applicant’s AMR for cracks, distortion, and increase in component stress level due to settlement is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(6) Erosion of porous concrete subfoundation

The GALL Report states that erosion of cement from porous concrete subfoundations beneath containment basemats is described in IN 97-11. IN 98-26 proposes Maintenance Rule structures monitoring for managing this aging effect, if applicable. If a dewatering system is relied upon for control of erosion of cement from porous concrete subfoundations, then the applicant is to ensure proper functioning of the dewatering system through the period of extended operation.

In LRA 3.5.2.2.2.1, the applicant stated that the evaluation of Information Notice 98-26 concluded that porous concrete subfoundations were not used at BFN. A dewatering system is not relied upon for control of erosion of cement from porous concrete subfoundations. Therefore, reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation are not applicable.

The staff concluded that the applicant’s AMR for reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation is consistent with the GALL Report, and that these aging effects are not applicable.

(7) Corrosion of structural steel components

The GALL Report states that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the Structures Monitoring Program is to include requirements to address monitoring and maintenance of protective coatings.

In LRA Section 3.5.2.2.2.1, the applicant stated that the Structures Monitoring Program will manage loss of material due to corrosion of structural steel components. The Structures Monitoring Program procedures specify visual inspections of structural conditions as the method used to detect degradation.

The applicant further stated that, for the steel that is embedded/encased within the concrete, corrosion is not an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and allow for the intrusion of aggressive ions causing a reduction in concrete pH. Aging management of previously noted concrete aging effects will manage loss of material for steel that is embedded/encased within concrete.

The applicant also makes note that NUREG-1557, Table B9, states that steel piles driven in undisturbed soil have been unaffected by corrosion and those driven in disturbed soil experience minor to moderate corrosion to a small area of metal. Loss of material for steel piles driven in undisturbed or disturbed soil does not require aging management.

The applicant also stated that the protective coating monitoring and maintenance program is not credited for aging management of loss of material for structural steel components.

The staff concluded that the applicant's AMR for loss of material due to corrosion of structural steel components is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff also concurred with the applicant's AMR for steel piles, because it is based on a documented staff technical assessment.

(8) Elevated temperatures

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 with the exception of the main steam tunnels in the reactor building BFN reinforced concrete structures have general area temperatures less than 150 °F during normal operation. General area temperatures have been conservatively evaluated using maximum normal space ambient temperatures noted on the harsh environmental drawing series and associated calculations. The main steam tunnels have a maximum normal space ambient temperature of 160 °F, as noted in the harsh environmental drawing series and associated calculations. This is a maximum normal space ambient temperature. The harsh environmental drawing series and associated calculations identify the space average normal ambient temperature as 135 °F. This is judged to be acceptable by the applicant, because when concrete is subjected to prolonged exposure to elevated temperatures reductions in excess of 10 percent of the compressive strength, tensile strength, and the modulus of elasticity begin to occur in the range of 180 °F to 200 °F.

The applicant further stated that each drywell is cooled during normal plant operation by a closed-loop ventilation system designed to keep the average temperature in the drywell less than 150 °F. The general area temperature inside the drywell (primary containment) is maintained below 150 °F as required by Technical Specifications. Elevated temperatures on internal concrete components such as the reactor support pedestal, where the temperature could approach 150 °F, are addressed as appropriate by BFN civil design criteria. The drywell concrete structure surrounding the drywell vessel was evaluated for thermal effects from the general area temperature of the drywell. The upper elevations of the sacrificial shield wall may exceed 150 °F briefly and infrequently, during abnormal operations; this is not considered to affect its function.

The applicant concluded that the conditions identified in the GALL Report are satisfied and aging management for reduction of strength and modulus due to elevated temperature for concrete components is not required.

During the audit, the staff requested the applicant to:

(1) Explain how the elevated temperature on internal concrete components, where the temperature could approach 150 °F, are addressed by BFN civil design criteria.

(2) Discuss the evaluation of the drywell concrete structure for thermal effects.

(3) Discuss the technical basis for concluding that “the upper elevations of the sacrificial shield wall may exceed 150 °F briefly and infrequently, during abnormal operations and is not considered to affect its functions.”

(4) Discuss the local temperatures that can be expected in the concrete surrounding hot piping penetrations and what provisions exist for maintaining these temperatures within acceptable limits.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the GDC document, BFN-50-C-7100 “Design of Civil Structures” (DC), provides the design basis requirements for all BFN structures, including the primary containment. In DC Section 3.2.5, Appendix C, the temperature requirements are defined for the drywell concrete, with an operating temperature of 150 °F specified for the drywell.

DC Appendix C, Table 15-10, “Reactor Support Pedestal Design Data,” provides the principal design cases for the reactor support pedestal and includes the requirement to consider thermal effects for each principal design case. DC Appendix C, Table 15-12, “Reactor Building Concrete Structure Fuel Pool Storage Pool and Dryer/Separator Storage Pool Design Data,” requires the consideration of drywell thermal rise for the appropriate principal design cases for the spent fuel storage pool and dryer/separator storage pool of the reactor building. Both these pools have structural elements that form portions of the outer structural concrete shell of the primary containment steel shell. DC Appendix C, Table 15-15(a), “Drywell Concrete Structure,” provides the principal design cases for the drywell concrete and requires the consideration of thermal effects in the principal loading combinations for the drywell concrete structure.

The applicant further stated that the sacrificial shield wall provides a biological shield for protection of personnel from gamma radiation, a neutron shield to prevent activation of the drywell components during operation, and a means of supporting the drywell pipe hangers and access platform. It also provides protection against damage to the nuclear system process barrier due to seismic loading, against further damage due to vessel pipe penetration rupture jet forces, and a limit stop and support for pipe restraints in the event of a drywell pipe rupture. It consists of a 24-foot diameter circular cylinder attached to the vessel support pedestal and extending upward approximately 45 feet. The sacrificial shield wall is 27 inches thick and is constructed from 26-inch vertical WF beam columns, tied together by horizontal WF beams and 1/4-inch plates.

The applicant stated that the ¼-inch plates are welded to the column flanges, both inside and outside, thereby forming a double-walled shell. This shell is filled with concrete to provide biological shielding capability. The concrete was assumed to have no structural purpose, except for the lowest 10 feet 6 inches of the wall. Based on the design criterion that the concrete has no structural purpose except for the lowest 10.5 feet, the applicant concluded that “the upper elevations of the sacrificial shield wall may exceed the 150 °F briefly and infrequently during abnormal operation and is not considered to affect its function," as stated in LRA 3.5.2.2.2.1, Item 8.

In its response, the applicant also noted that degradation of drywell concrete due to elevated temperature would be addressed in its response to RAI 3.5-5. This issue will be dispositioned in the staff evaluation of the applicant's response to RAI 3.5-5.

(9) Aging Effects for Stainless Steel Liners for Tanks

In LRA Section 3.5.2.2.2.1, the applicant stated that BFN does not have any Group 7 structures or in-scope stainless steel liners in an exposed-to-fluid environment for any Group 8 structures. The staff concluded that further evaluation of this aging effect is not applicable.

In summary, the staff found that the applicant had demonstrated that the effects of aging, with the exception of elevated temperatures, will be adequately managed by the Structures Monitoring 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).

3.5.2.2.9 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.

SRP-LR Section 3.5.2.2.2.2 states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and 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 Groups 1-3, 5, 7-9 structures, if an aggressive below-grade environment exists. ISG-3 identifies additional requirements.

The GALL Report, as updated by ISG-3, states that for inaccessible areas, a plant-specific AMP is required (may be part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5; chlorides > 500 ppm; or sulfates > 1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report also notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is nonaggressive.

In LRA Section 3.5.2.2.2.2, the applicant stated that design and construction of reinforced concrete provides dense, well cured, and low permeability concrete with an acceptable degree of protection for the embedded steel against exposure to an aggressive environment. Cracking of concrete is controlled through proper arrangement and distribution of reinforcing steel.

The applicant further stated that continued or frequent cyclic exposure to the following aggressive environments is necessary for aggressive chemicals to cause significant aggressive chemical attack or corrosion of embedded steel:

- acidic solutions with pH less than 5.5
- chloride solutions greater than 500 ppm
- sulfate solutions greater than 1500 ppm

The applicant stated that aggressive chemicals are present at plant sites, system leakage is leakage that could cause aggressive chemical attack is possible. However, leaks are not expected to continue for the extensive periods required for degradation, and repairs would be completed prior to loss of intended function. An aggressive environment may also occur where concrete is exposed to aggressive aqueous solutions such as groundwater or aggressive water flow. Groundwater sample measurements confirm that parameters are below threshold limits that could cause aggressive chemical attack for below-grade inaccessible concrete. Natural groundwater movement in this area is from the plant site to Wheeler Reservoir. Wheeler Reservoir water samples also confirm that an aggressive environment does not exist. Therefore, the applicant concludes that the conditions identified in the GALL Report, as revised by ISG-03, are satisfied and aging management of cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond and loss of material due to corrosion of embedded steel is not required for below-grade inaccessible concrete.

The applicant concluded that Browns Ferry groundwater and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist) and that the rate of groundwater flow is not considered aggressive.

The applicant stated that BFN does not commit to periodic groundwater monitoring over the period of license extension, since it is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Browns Ferry. A change in the environment due to a chemical release would be considered an abnormal event. SRP-LR states that aging effects from abnormal events need not be postulated specifically for license renewal.

The staff found that the applicant’s response is not consistent with the GALL Report recommendation for periodic monitoring of groundwater. This issue was dispositioned by the staff, based on the applicant’s responses to RAIs 3.5-7 and 3.5-8 and is discussed in SER Section 3.5.2.3.2.

3.5.2.2.10 Aging of Supports Not Covered by Structures Monitoring Program

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.

SRP-LR Section 3.5.2.2.3.1 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 due to degradation of the surrounding concrete for Groups B1-B5 supports; (2) loss of material due to environmental corrosion for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

(1) Reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1 through B5 supports.

    In LRA Section 3.5.2.2.3.1, the applicant stated that reduction in concrete anchor capacity due to local concrete degradation for Groups B1 – B5 supports will be managed by the Structures Monitoring Program.

(2) Loss of material due to environmental corrosion, for Groups B2-B5 supports.

    In LRA Section 3.5.2.2.3.1, the applicant stated that loss of material due to environmental corrosion for Groups B2 – B5 Supports will be managed by the Structures Monitoring Program.

(3) Reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports.

    In LRA Section 3.5.2.2.3.1, the applicant stated that there are no vibration elements within the scope of license renewal.

The staff found that the applicant had appropriately evaluated AMR results involving management of aging of component supports, as recommended in the GALL Report. The staff found that the applicant had 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).

3.5.2.2.11 Cumulative Fatigue Damage due to Cyclic Loading

Cumulative fatigue damage is a TLAA. TLAAs are evaluated in SER Section 4.

3.5.2.2.12 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides a separate 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 claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had 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).

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.5.2.1 through 3.5.2.26, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.5.2.1 through 3.5.2.26, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. During the onsite audit, the staff reviewed selected items in all applicable LRA Table 3.5 items for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Carbon Steel in an Embedded/Encased Environment - It is recognized that all metals embedded/encased in concrete are inaccessible; however, they could be susceptible to aging degradation. The staff requested that the applicant provide an AMR for further evaluation of embedded/encased components if aging of components in accessible areas is identified that may indicate aging of the inaccessible components.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM Code standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.

The applicant further stated that concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

The applicant also stated that, as a minimum, all exposed portions of embedded/encased carbon steel structural components are inspected by the Structures Monitoring Program for the following aging effects:

- outside air environments: loss of material due to general and pitting corrosion
- inside air environments: loss of material due to general corrosion
- containment air environments: loss of material due to general corrosion

The applicant concluded that the condition of the exposed portion of the embedded/encased carbon steel will provide an indication of the condition of the embedded/encased portion of the carbon steel. If a deficient condition were identified for the exposed portion of the embedded/encased carbon steel material, the Corrective Action Program (SPP-3.1) would document the deficient condition. Resolution of the deficient condition would require the development of a corrective action plan and consideration would be given to the extent of the deficient condition in the development of the corrective actions, which would include the embedded/encased portion of the material as warranted by the deficient condition.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for carbon steel components embedded/encased in concrete.

The staff found that the applicant had identified an appropriate course of action, through its Corrective Action Program, to manage aging of carbon steel components embedded/encased in concrete, if a deficient condition is identified for the exposed portion of the embedded/encased carbon steel material. On this basis, the staff accepts the applicant's AMR results for carbon steel in an embedded/encased environment.

<u>Stainless Steel in Containment Air, Inside Air and Outside Air Environments</u> - The staff requested that the applicant provide the technical basis for concluding that the BFN stainless steel components do not require aging management for any aging effects/mechanisms in containment atmosphere, inside air, and outside air environments.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the AMR evaluation for stainless steel in a containment atmosphere, inside air, and outside air is not susceptible to loss of material in for these environments. Stainless steels form a passive film that prevents corrosion. Only a corrosive wetted environment is conducive to promoting aging degradation of stainless steel. Alternate wetting and drying in an outside air environment has shown a tendency to 'wash' the exterior surfaces, cleaning the surface rather than concentrating any corrosive contaminants (ref EPRI 1003056 Mechanical Tools). SCC of stainless steel, which is only considered plausible in wetted corrosive environments greater than 140°F, will not occur in the containment atmosphere environment, inside air environment, or outside air environment.

The staff found the applicant's AMR results to be acceptable for stainless steel structural components and stainless steel non-ASME supports. In the absence of corrosive contaminants and temperatures greater than 140°F, stainless steel material is not susceptible to loss of material due to corrosion and cracking due to SCC. Therefore, aging management for loss of material and cracking in the containment atmosphere environment, an inside air environment, or an outside air environment is not required.

In its response, the applicant also stated that ASME stainless steel equivalent supports are subject to the requirements of ASME Code Section XI, Subsection IWF during the period of extended operation. However, the staff determined that the applicant had not credited IWF for aging management of ASME stainless steel equivalent supports during the extended period of operation, because the applicant's AMR had not identified any applicable aging effects. The staff requested additional information to resolve this issue and related issues. The disposition is discussed in SER 3.5.2.3.26, as part of the review of LRA Table 3.5.2.26 AMRs.

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 the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.5.2.3.1 Primary Containment Structures – Summary of Aging Management Evaluation – Table 3.5.2.1

The staff reviewed LRA Table 3.5.2.1, which summarizes the results of AMR evaluations for the primary containment structures component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.1, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Lubrite in a Containment Air Environment</u> – The staff requested that the applicant describe where the referenced items are used and provide the technical basis for concluding that no aging management of the lubrite plates used in BFN is required in a containment atmosphere.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1, row 37 applies to the lubrite plates used for the drywell floor beam seats. EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1," states that lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. Lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The containment atmosphere at the location of the drywell floor beam seats is not an aggressive or wetted environment.

The applicant also stated that a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4" and NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," concur that there are no lubrite plate aging effects that require aging management.

Based on the additional information provided by the applicant, the staff finds the applicant's AMR results for lubrite plates to be acceptable. Prior staff evaluations of this issue have concluded that there are no aging effects requiring aging management.

The staff's review of LRA Table 3.5.2.1 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI 3.5-1, dated December 10, 2004, the staff inquired about the leakage rate testing of containment penetration bellows by pointing out that LRA Table 3.5.1, Item Numbers 3.5.1.3 and 3.5.1.17, indicate that the AMR results are consistent with the GALL Report, with the exceptions described in ASME Code Section XI Subsection IWE Program. The GALL Report, Item B.1.1.1-d recommends further evaluation regarding the SCC of containment bellows. In the discussion of these items in LRA Section 3.5.2.2.1.7, the applicant asserted that Appendix J, Type B testing was effective in detecting leakages through the vent line bellows, as well as through other pressure boundary bellows. The staff requested the applicant to provide additional information regarding the frequency of Type B testing (performance-based intervals, in accordance with Option B, Appendix J) of containment pressure boundary bellows at Units 2 and 3, and the status of these bellows for Unit 1.

In its response, by letter dated January 31, 2005, the applicant quoted the content of LRA Section 3.5.2.2.1.7 and then stated:

> BFN pipe penetration bellows are 10 CFR 50, Appendix J, Type B tested. BFN vent line bellows are 10 CFR 50, Appendix J, Type A tested.
>
> Type B and C tests are performed prior to initial reactor operation. Subsequent Type B and C tests are performed at a frequency of at least once per 30 months until performance data are collected for evaluation for extended test interval in accordance with RG 1.163. Type B tests may use an extended interval of up to 120 months (excluding airlocks). Unit 2 and 3 bellows are tested at a 60-month test interval. There have been no bellows failures on either Unit 2 or 3 bellows. Prior to the restart of Unit 1, Appendix J, Type B testing of containment pipe penetration bellows will be performed. Unit 1 bellows will be tested at least once per 30 months until test performance data is available to justify an extended test interval under Option B.

The staff noted that the vent line bellows are single-ply, and their leakage rates and aging degradation are managed by Appendix J, Type A testing. As Appendix J, Type A testing is generally performed at 10-year intervals or greater, it was not clear to the staff how the leaktightness and structural integrity of the vent line bellows were maintained. The applicant was requested to provide the frequency at which the Type A testing is performed in each unit, and the process by which the integrity of the vent line bellows is maintained, including corresponding operating experience.

In its letter dated May 31, 2005, the applicant stated that it has been granted a one-time 5-year extension by the staff for performing the Type A test, and emphasized that there had been no performance-based Type A test failure on Units 2 or 3. The applicant plans to perform an Appendix J, Type A integrated leak rate test (ILRT) on Unit 1 prior to restart. The Unit 1 Appendix J, Type A test will be performed at least once every 48 months until test performance data are available to justify an extended test interval under Option B. Moreover, the applicant provided a detailed description of the history of the visual examinations performed under its plant procedures 2-TI-173 and 3-TI-173 which performs a general visual examination each inspection period (three periods per 10 year interval). Different from other BWR Mark I containments, the single-ply vent line bellows at the three BFN units are accessible for examination from the torus interior. A VT-3, visual examination is performed each inspection interval in accordance with plant procedure 0-TI-376. The applicant emphasized that these examinations are thorough as they are performed by NDE-certified personnel with specific lighting and visual acuity requirements. Additionally, plant procedure 0-SI-4.7.A.2.K, “Primary Containment Drywell Surface Visual Examination,” is performed each operating cycle.

Based on the detailed response regarding the detection of flaws in vent line bellows provided by the applicant, the staff found the applicant's process for ensuring the integrity of the vent line bellows acceptable. Therefore, the staff's concern described in RAI 3.5-1 is resolved.

In RAI 3.5-2, dated December 10, 2004, the staff stated that, for seals and gaskets related to containment penetration, LRA Table 3.5.1, Item Number 3.5.1.6 and component type, "Compressible Joints and Seals," in LRA Table 3.5.2.1, the ASME Code Section XI Subsection IWE Program and the 10 CFR 50 Appendix J Program have been identified as AMPs. Based on Exception 1 in the ASME Code Section XI Subsection IWE Program, the AMP will not be applicable for aging management of containment seals and gaskets. For equipment hatches and air-locks, the assumption is that the leak rate testing program will monitor aging degradation of seals and gaskets, as they are leak rate tested after each opening. Therefore, the staff requested that the applicant clarify whether these assumptions are correct. For other penetrations (mechanical and electrical) with seals and gaskets, the applicant was requested to provide information regarding the adequacy of Type B leak rate testing frequency to monitor aging degradation of seals and gaskets of containment drywells. The applicant was also requested to provide the status of seals and gaskets of these penetrations at Unit 1.

In its response, by letter dated January 31, 2005, the applicant stated:

> ASME Section XI, 1992 Edition, 1992 Addenda, Category E-D, Item Numbers E5.10 (Seals), and E5.20 (Gaskets) requires a visual examination, VT-3, of containment seals and gaskets. Examination of most seals and gaskets requires the joints to be disassembled. When the airlocks, hatches, electrical penetrations, and flanged connections are tested in accordance with 10 CFR 50, Appendix J, degradation of the seal or gasket material would be revealed by an increase in the leakage rate. Corrective measures would be applied and the component retested.
>
> For Units 1, 2, and 3, Relief Request CISI-1 was granted to perform Appendix J test in lieu of the visual examination, VT-3, on the containment seals and gaskets. The moisture barriers continue to receive a visual VT-3 examination in accordance with Category E-D for Units 1, 2, and 3. The scope of the 10 CFR 50 Appendix J Program includes all pressure-retaining components, the containment shell (drywell and torus) and penetrations. The following components are included in the scope of the program:
>
> - containment penetration seals on airlocks, hatches, spare penetrations with flange connections, electrical penetrations and other devices required to assure containment leak-tight integrity;
> - containment penetration gaskets on airlocks, spare penetrations with flange connections, and other devices required to assure containment leak-tight integrity;
> - pressure retaining bolted connections;
> - containment penetration bellows; and
> - airlocks.
>
> Units 2 and 3 O-ring seals (flanges, hatches, etc.) are tested on either a 30 or 60-month interval. Seal failures have occurred sporadically since restart. The Unit 2 and Unit 3

> drywell heads have experienced failures and are currently classified as Maintenance Rule (a)(1) for corrective actions. There are currently no electrical penetration performance problems on Unit 2. All electrical penetrations on Unit 2 are currently on a 120-month test interval. Testing has identified only minor problems such as gauge, tubing, and root valve leaks. Unit 3 electrical penetrations are on 30, 60, or 72-month test intervals. In general, testing has identified only minor problems such as gauge, tubing, and root valve leaks. However, one electrical penetration (3-EPEN-100-0101C) on Unit 3 experienced a failure, was repaired, and is being tested on a 30-month test interval. Other electrical penetrations are being tested at a 60-month interval. The remainder of the Unit 3 electrical penetrations are on a 72-month interval.
>
> Type B testing will be performed as part of the Unit 1 restart effort and will continue at least once per 30 months until test performance data is available to justify an extended test interval under Option B.

The applicant described the existing process used in identifying degradation of the primary containment penetration seals and gaskets and plans to continue with the testing and corrective action process during the period of extended operation. Therefore, the staff found the applicant's process for managing the aging of the pressure-retaining seals and gaskets of primary containments acceptable. The staff's concerns described in RAI 3.5-2 are resolved.

In RAI 3.5-3, dated December 10, 2004, the staff stated that the containment drywell-head to drywell joint consists of a pressure unseating containment boundary with pre-loaded bolts. Loosened bolts and deteriorated gasket and/or seals can breach containment pressure boundary. Exceptions 1 and 2 taken in the ASME Section XI Subsection IWE Program will preclude examinations of seals and bolts of this joint. Only Type A leak rate testing and associated visual examination requirements of the 10 CFR 50 Appendix J Program can be relied upon to detect defects and degradation of this joint. The test interval for Type A leak rate testing can be 10 to 15 years. Therefore, the staff requested the applicant to provide (1) information regarding the plans and programs that are used to ensure the integrity of this joint for each containment and (2) the status of the components (O-rings and bolts) at this joint for Unit 1.

In its response, by letter dated January 31, 2005, the applicant stated:

> These containment pressure boundary components will continue to be inspected consistent with the Browns Ferry CLB for 10 CFR Part 50, Appendix J requirements. On Units 2 and Unit 3 the Type A test frequency is currently on a 10-year interval. There have been no performance based Type A test failures on Unit 2 or Unit 3. A Type A Integrated Leak Rate Test will be performed as part of the Unit 1 restart effort. Type B testing is also performed on the drywell-head seal every refueling outage for all three units. Therefore, in combination of the Type A tests and Type B tests, integrity for this joint for each containment is assured. Exception 2 pertains to bolt torque or tension testing. Pressure retaining bolting associated with the Containment drywell-head to drywell joint is examined in accordance with ASME Section XI Subsection IWE.

The applicant performs Type B testing of the drywell-head seal every outage, and examines the pressure retaining bolts of the drywell head in accordance with Subsection IWE of the ASME Section XI Code. The staff accepts that these two activities together with periodic Type A testing will ensure the integrity of this joint. Therefore, the staff found the applicant's practice of ensuring the integrity of this joint acceptable. The staff's concern described in RAI 3.5-3 is resolved.

In RAI 3.5-4, dated December 10, 2004, the staff stated that the water leakages from the sand drains have been found in Units 2 and 3, and the results of the UT examinations performed from the accessible areas of the drywells have indicated that the condition of the drywell shells was good, and these areas did not require augmented examination. Therefore, the staff requested that the applicant provide the following additional information related to the drywell shell corrosion in this area for each containment drywell:

a. In other Mark I containments, the cause of water leakage from the sand-bed drains has been found to be water leaking from the refueling cavity (see IN 86-99, "Degradation of Steel Containments)." As no water leakage has been indicated from Unit 1 (having no refueling activities during its long layup), it would appear that the cause of the water leakage in Units 2 and 3 could be the same as that described in the information notice. Provide a discussion of the root cause in this context.

b. If the water leakage is related to refueling operation, provide information regarding the corrosion susceptibility of the cylindrical part of the drywell shell on the insulation (inaccessible) side.

c. Item No. E4.12 of Examination Category E-C of Subsection IWE requires the owner to establish grid and measurement locations in the suspect areas identified for augmented examinations. Provide information regarding the methods used to establish a confidence level that no drywell shell corrosion exists in the sand-pocket areas.

d. Unless preventive actions are taken and conditions verified that no leakage and shell corrosion exists in the suspect areas, IWE will require continuation of UT measurements in the augmented examination areas. Provide justification for excluding the suspect areas from augmented examinations.

e. Based on the results of the UT examinations performed from the accessible areas of the drywells, BFN asserted that the condition of the drywell shells is good. Provide a discussion of BFN's criteria for judging that the condition of the drywell steel liner plate is good and the rationale for the criteria.

f. Provide a discussion of any degradation observed and/or repair work implemented as a result of past general visual inspection of the moisture barrier located at the junction of the steel drywell and the concrete floor.

In its response, by letter dated January, 31, 2005, the applicant stated:

a. See response to item "b."

b. A postulated failure of the drywell-to-reactor building refueling seal can result in water intrusion into the annulus space around the drywell. This leakage can occur only during refueling outages when the reactor cavity is flooded to allow movement of fuel between the reactor and the fuel pool. However, water intrusion does not cause failure of the drywell's intended function. Any water leakage resulting from a postulated failure of the drywell-to-reactor building refueling seal could not remain suspended in the annulus region for an indefinite period of time and would eventually be routed to the sandpocket area drains or would evaporate due to the heat generated in the drywell during operation. In TVA's response to NRC Generic Letter 87-05 dated August 30, 1988, which addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region," TVA provided the NRC with the results of the ultrasonic testing for corrosion degradation of drywell liner plate. The results of the ultrasonic testing states: Each unit's drywell was ultrasonically tested near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. Below are the results of each unit's drywell ultrasonic testing:

- Unit 1 - No reading below the nominal thickness of one inch was measured indicating that the integrity of the drywell liner plate is maintained. Periodic leakage from the sand cushion area has been observed. Corrosive species in the drainage are bases to suspect a higher rate of corrosion on Unit 1 drywell liner plate than on Unit 2 and 3. However, objective evidence of serious corrosion damage was not noted.
- Unit 2 - No reading below the nominal thickness of one inch was measured indicating that no damage to the integrity of the drywell liner plate has occurred.
- Unit 3 - No reading below the nominal thickness of one inch was measured indicating that no damage to the integrity of the drywell liner plate has occurred.

c. In response to NRC Generic Letter 87-05, TVA provided the NRC with the results of the ultrasonic testing for corrosion degradation of BFN Units 1, 2, and 3 drywell liner plates near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. Paragraph IWE-1242 of ASME Section XI requires the Owner to determine containment surface areas requiring augmented examination, in accordance with Paragraph IWE-1241. UT thickness measurements of this area were obtained during the U2C10 and U3C8 refueling outages for Units 2 and 3 respectively and in 1999 and 2002 for Unit 1 (0-TI-376 Appendix 9.7 page 4). The data indicate that the condition of the drywell steel liner plate in this area meets code requirements, and that this area should not be categorized for augmented examination.

d. See response to Item c.

e. See response to Item c.

f. The internal drywell steel containment vessel (SCV) embedment zone is subject to corrosion if the drywell floor-to containment vessel moisture barrier fails, allowing moisture intrusion, or if the concrete floor of the drywell cracks, allowing moisture seepage through to the steel liner. During the Unit 2 Cycle 9 outage, a portion of the moisture barrier was replaced (Problem Evaluation Report (PER) BFPER971516). Engineering personnel performed an examination of the exposed drywell SCV area below the moisture seal. This inspection indicated some minor pitting and localized rust, but nothing approximating a challenge to nominal wall thickness. No propagation of iron oxide to the concrete surface was noted, which would be indicative of steel containment vessel corrosion below the concrete. Inspections conducted by the Containment ISI Program during Unit 2 Cycle 10 refueling outage and Unit 3 Cycle 9 refueling outage also identified some damaged areas of the moisture barrier (gaps, cracks, low areas/spots, or other surface irregularities) that were evaluated by engineering and replaced or repaired. (PER 99-005254-000 for Unit 2 Drywell moisture seal barrier and PER 00-004163-000 for Unit 3 Drywell moisture seal barrier).

In Unit 1, the moisture barrier in areas that would be made inaccessible due to ductwork installation have been replaced. Visual examination of exposed drywell SCV area below the moisture barrier identified some minor pitting. Ultrasonic thickness and pit depth measurements were taken and evaluated by engineering which confirmed nominal wall thickness was not encroached. The entire Unit 1 moisture barrier will be replaced before restart.

The Structures Monitoring Program also monitors the concrete to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell. Research of plant history did not reveal any instances of water spills and water ponding on the containment concrete floor. A general visual inspection of the moisture barrier at the junction of the steel drywell shell and the concrete floor is performed once each inspection interval in accordance with the ASME Section XI, Subsection IWE aging management program.

Based on the responses, the staff understood that for each unit the applicant has taken actions to monitor corrosion of the outside surface of the drywell shell and the inside surface at the junction of the concrete floor and the drywell shell. However, the extent of monitoring the parameters associated with the degradation and the root cause(s) of the corrosion problems are not clear.

The response to RAI 3.5-4 emphasizes that the existing degradation of the drywell shells (inside and outside) has not reached the minimum required thickness of one inch. However, the response does not address a number of parameters that are pertinent to the period of extended operation. In a follow-up to RAI 3.5-4, dated April 5, 2005, the applicant was requested to provide (1) a description of the type of degradation (e.g, a cluster of pits or general corrosion), (2) a description of preventive actions (e.g. stopping the leaks from the refueling cavity seals or monitoring of sand drains), (3) a description of corrective actions (repairing/cleaning and recoating degraded areas), (4) a description of the extent of degradation, and (5) when IWE-1240 requirement for augmented inspection will be implemented.

In its letter dated May 31, 2005, the applicant stated that during each refueling outage since the mid-1980s, a visual inspection of the interior surface of the drywell, and the interior and exterior surface of the drywell head and torus (suppression chamber) was performed to verify structural integrity. These inspections are performed per SI 0-SI-4.7.A.2.K, “Primary Containment Drywell Surface Visual Inspection,” and BFN Technical Instruction 0-TI-417, “Inspection of Service Level I, II, III Protective Coatings.” SI 0-SI-4.7.A.2.K originally included the exam requirements for the visual inspections of the protective coatings but was revised in March 2001 to remove those requirements and add the reference to BFN Technical Instruction 0-TI-417 for coating inspections. BFN Technical Instruction 0-TI-417 was written to incorporate the information for performing visual inspections of Service Level I protective coatings (design-basis accident (DBA) and non-DBA qualified). This procedure was implemented in March 2001. The scope of SI 0-SI-4.7.A.2.K, as defined in the procedure, is as follows:

(1) Includes provisions for the visual verification of the structural components of the drywell, drywell head, torus (suppression chamber), and the exterior surfaces of the drywell head

and torus (suppression chamber) (i.e., piping, connections, structural supports, penetrations, platform steel, duct supports, concrete walls, and steel shell) by visually inspecting for deterioration and/or structural damage.

(2) Provides visual inspection of the moisture seal barrier located on drywell elevation 550 feet.

(3) Provides for visual inspection of the interior surfaces of the drywell and torus (suppression chamber) above the level one foot below the normal water line and exterior surface of the torus (suppression chamber) below the water line each operating cycle for deterioration and any signs of structural damage with particular attention to piping connections and supports and for signs of distress or displacement. In its response, the applicant provided the results of the earlier inspections of the drywell internal components for each unit.

Based on the detailed response, the staff found that the applicant has in place detailed procedures for examining the concrete and steel components inside the drywell, and systematic acceptance criteria. The applicant plans to continue this process during the extended period of operation. Therefore, the staff found the applicant’s process of detecting degradation of these components adequate and acceptable, and the staff’s concern described in RAI 3.5-4 is resolved.

In RAI 3.5-5, dated December 10, 2004, the staff stated that a number of load-bearing reinforced concrete structures within the drywell shell were subjected to temperatures higher than the established threshold of 150 °F, as discussed in LRA Section 3.5.2.2.2.1. The effectiveness of the closed cooling ventilation system is paramount in preventing large temperature excursions in the drywells. Therefore, the staff requested that the applicant provide the following information related to the concrete structures within the drywells of each unit.

a. Provide a summary of the operating experience related to the reliability of the closed cooling ventilation system.

b. Provide a summary of the results of the last inspections performed on (1) reactor pressure vessel (RPV) pedestal supports, (2) the foundation and floor slab, and (3) the sacrificial shield wall under the existing Structural Monitoring Program.

c. LRA Section 3.5.2.2.2.1, Item 8, states that the main steam tunnels in the reactor building at Units 1, 2, and 3 have a maximum normal space ambient temperature of 160 °F. Provide a discussion, including a summary of the results of the engineering analysis performed, to support the conclusion that the conditions identified in the GALL Report are satisfied and that aging management of reduction of strength and modulus due to elevated temperature for the affected concrete components is not required.

In its response, by letter dated January 31, 2005, the applicant stated:

> Note that LRA Section 3.5.2.2.2.1, Item 8 states in part: "The upper elevations of the sacrificial shield wall may exceed 150 °F briefly and infrequently, during abnormal operations and is not considered to affect its function.” The upper elevation of the sacrificial shield wall inside the drywell shell is not a load bearing reinforced concrete structure.

a. The drywell closed cooling ventilation system is a non-safety related system and not in scope for License Renewal. This function is not required for Safe Shutdown of the plant. If this cooling system function is lost, operator action will be required when the Technical Specifications for drywell temperature limits exceeds 150 °F.

b. A review of Browns Ferry Structures Monitoring Baseline inspection and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects of the RPV pedestal supports, the foundation and floor slab, and the sacrificial shield wall.

c. Appendix A of ACI 349-85 specifies that the concrete temperature limits for normal operation or any other long term period shall not exceed 150 °F except for local areas, which are allowed to have increased temperatures not to exceed 200 °F. With the exception of the main steam tunnels in the Reactor Building, BFN reinforced concrete structures have general area temperatures less than 150 ºF during normal operation. The general area temperatures have been conservatively evaluated using maximum normal space ambient temperatures noted on the Harsh Environmental drawing series and associated calculations. The Unit 1, 2, and 3 main steam tunnels at BFN have a maximum normal space ambient temperature of 160 ºF as noted in the Harsh Environmental drawing series and associated calculations. Note however, that this is a maximum normal space ambient temperature. The TVA Harsh Environmental drawing series and associated calculations identify the average normal space ambient temperature as 135 ºF. This is judged to be acceptable because when concrete is subjected to prolonged exposure to elevated temperatures, reductions in excess of 10 percent of the compressive strength, tensile strength, and the modulus of elasticity only begin to occur in the range of 180 ºF to 200 ºF. (Reference EPRI TR-103842, July 1994).

   Therefore, the conditions identified in NUREG-1801 are satisfied and aging management of reduction of strength and modulus due to elevated temperature for concrete components at BFN is not required.

The staff recognizes the temperature thresholds, and accepts the EPRI TR position. However, at these temperatures, the concrete structures go through additional shrinkage cracking, and spalling. The staff's basic concern was related to the degradation of pedestals supporting the reactor vessels and that of the seismic restraints anchored to the sacrificial shields and the drywell. The staff expected more description regarding the concerns in response to item "b." In this context, in a follow up letter, April 5, 2005, the applicant was requested to provide (1) the type and extent of degradation observed in the reactor pedestals and at the seismic restraint anchorage areas, and (2) the acceptance standards established (e.g., ACI 349-3R, ASME Code Subsection IWE) for corrective actions.

In its response, by letter May 24, 2005, the applicant stated that the inspection of concrete within the drywell is conducted per BFN "Procedure Walkdown of Structures for Maintenance Rule" (LCEI-CI-C9). This LCEI provides the basis for monitoring/inspection tasks, examination criteria, evaluation requirements, and acceptance criteria in compliance with the Maintenance Rule. A baseline inspection was established in 1997 and subsequent inspections are performed on a five-year frequency. LCEI-CI-C9 Section 7.2 provides inspection guidelines, and visual inspections of structural conditions are used to detect degradation. Visual inspection is an acceptable technique and is consistent with techniques identified in industry codes and standards such as ACI 349.3R-96. Inspection checklists (LCEI-CI-C9 Attachment 1) are used to document inspection results/defects.

LCEI-CI-C9 Section 7.3 provides guidance for evaluation of the results documented on the inspection checklists. The acceptance criteria are defined in LCEI-CI-C9 Section 7.3 as: (1) acceptable, (2) acceptable with deficiencies, and (3) unacceptable. The latest inspection of the concrete of the reactor vessel support pedestal, biological or sacrificial shield wall, and other structural concrete within the primary containment structure had been completed by 2002 for Units 2 and 3. All concrete elements within the primary containment structure for Units 2 and 3 were found to be acceptable.

The staff found the inspection procedure used to detect deterioration of the concrete structures inside drywell adequate and acceptable, as its continued use during the period of extended operation will ensure the intended functions of these components. Therefore, the staff's concern described in RAI 3.5-5 is resolved.

In RAI 3.5-6, dated December 10, 2004, the staff stated that LRA Table 3.5.2.26 is silent on the AMR related to Class MC supports. ASME Section XI Subsection IWE Program takes exception to NUREG-1801 Section XI.S3, and states that the aging effects for supports of MC components will be managed by the Structures Monitoring Program or Chemistry Control Program with associated One-Time Inspection Program for submerged supports during the extended period of operation. Therefore, the staff requested that the applicant provide the following information related to the aging management of Class MC supports:

- Provide the results of the AMR for (1) MC component supports within the BFN containments, (2) MC component supports outside the containments, and (3) supports for piping penetrating through the containments and designated as MC piping (if any). Also, summarize the program (sample size, inspection frequency, personnel qualification, etc.) used to arrive at the AMR results.
- Section 50.55a(g)(4) of 10 CFR requires the inservice inspections of Class MC pressure retaining components and their integral attachments, in accordance with the requirements of ASME Code Section XI. ASME Code Section XI Subsection IWF sets the examination requirements for Class MC supports, other than those for the MC piping supports. Therefore, provide justification for the exception taken in ASME Code Section XI Subsection IWF Program regarding the aging management of Class MC component supports.
- Subsections IWE and IWF do not incorporate explicit requirements for inservice inspection of supports of pipes designated as Class MC; therefore, the applicant was requested to provide a description of a proposed AMP (could be part of the Structural Monitoring Program), including sample size, the extent of examination, frequency of examination, and qualification of personnel who perform and evaluate the inspection results.

In its response, by letter dated January 31, 2005, the applicant noted that the information requests made in RAI 3.5-6 are addressed in the responses to RAIs 2.4-2, 2.4-13(a) & (b) and B.2.1.33, dated January 24, 2005. Finally, by letter dated May 31, 2005, the applicant agreed to bring the inspection and inspector qualification with regards to Class MC supports into the scope of ASME Section XI Subsection IWF Program (see SER Section 3.0.3.2.21 for staff evaluation of the ASME Section XI Subsection IWF Program). After comprehensively reviewing all responses to the indicated RAIs, above, the staff concluded that the applicant had successfully resolved all of the staff issues with regard to this and the other RAIs indicated.

The staff also reviewed the information provided in LRA Section 3.5.2.1.1 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the primary containment structures components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the primary containment structures components acceptable.

3.5.2.3.2 Reactor Buildings – Summary of Aging Management Evaluation – Table 3.5.2.2

The staff reviewed LRA Table 3.5.2.2, which summarizes the results of AMR evaluations for the reactor buildings component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.2, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Ceramic Fiber in an Inside Air Environment</u> - The staff requested that the applicant provide the BFN technical basis for concluding that no aging management is required for ceramic fiber fire barriers in an inside air environment.

The following list identifies the ceramic fiber components in an inside air environment:

- reactor building fire barriers
- diesel generator building fire barriers

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that ceramic and glass fiber used to seal fire barrier penetrations do not have any applicable aging effects requiring aging management. This is consistent with previous staff positions in that there are no applicable aging effects for glass used in a metal fire barrier penetration. This is also consistent with the NUREG-1769 "Safety Evaluation Report Related to License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," dated January 31, 2003,which concurred that insulation made of aluminum, stainless steel (mirror), calcium silicate, ceramic fiber, or fiberglass in a sheltered environment does not have any aging effects requiring aging management.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following ceramic fiber components.

- reactor building fire barriers
- diesel generator building fire barriers

The staff concluded that the applicant had not credited an existing AMP (structures monitoring and/or fire protection) that already includes fire barriers in its scope, on the basis that its AMR did not identify any applicable aging effects.

Earthfill & Rock in a Buried Environment - This item indicates that the equipment supports and foundations are earth fill (rock and sand). The staff requested that the applicant explain the technical bases for concluding that there are no aging effects requiring management.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the foundation for the condensate water storage tank (CWST) is comprised of a concrete ring foundation with the interior portion of the ring foundation filled with crushed rock and sand. The earthen materials (rock and sand) of the CWST foundation interior base are protected from environmental weathering conditions by the concrete perimeter ring and CWST tank bottom. There are no aging effects for the earthen materials of the CWST foundation interior base that require aging management. Aging management of the CWST concrete foundation ring is managed by the Structures Monitoring Program. Aging management of the CWST bottom will be performed by the One-Time Inspection Program.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for earthen materials of the CWST foundation interior base.

Based on the additional information provided by the applicant, the staff concurred with the applicant's AMR results for the crushed rock and sand base of the CWST. The staff concluded that aging management is not required because these materials are adequately protected by the concrete perimeter ring and the CWST tank bottom.

Elastomers in an Embedded/Encased Environment - The staff requested the applicant to clarify whether the compressible joints and seals that are embedded/encased in concrete are accessible for monitoring. If not, the staff requested the applicant to explain how the Structures Monitoring Program is utilized to manage aging effects in inaccessible areas.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.2, rows 4 and 5, apply to the seal around the reactor building access doors. Row 4 applies to the portion of the seal that is embedded/encased, and row 5 applies to the portion of the seal that is exposed to the inside air environment of the reactor building. An embedded/encased environment will minimize aging effects due to elastomer degradation caused by inside air environment (ambient conditions of ultraviolet radiation, ozone, temperature, etc.). The Structures Monitoring Program will periodically inspect the portion of the seal that is exposed to the inside air environment of the reactor building for aging effects due to elastomer degradation. The condition of the exposed portion of the seal will provide an indication of the condition of the embedded/encased portion of the seal. The inaccessible portions of the embedded/encased seal for the reactor building access door will be monitored with the periodic inspections of the seal that are exposed to the air environment of the reactor building.

Based on the additional information provided by the applicant, the staff finds the applicant's AMR results for the embedded/encased portion of the seal around the reactor building access doors to be acceptable. The condition of the exposed portion of the seal will be periodically inspected by the Structures Monitoring Program, which will provide an indication of the condition of the embedded/encased portion of the seal.

Stainless Steel in an Embedded/Encased Environment – All metals embedded/encased in concrete are inaccessible; however, they could be susceptible to aging degradation. The staff requested that the applicant provide an AMR to further evaluate embedded/encased components if aging of components in accessible areas is identified that may indicate aging of the inaccessible components.

The following list identifies stainless steel components that are embedded/encased:

- mechanical penetrations
- spent fuel pool liners

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

The applicant also stated that the AMR for the material and environment combination of stainless steel in an embedded/encased environment was performed and concluded that no aging mechanism was identified that requires management. The applicant noted that the submerged surfaces of spent fuel pool liners are managed by the Chemistry Control Program and monitoring of the spent fuel pool level is managed by plant operations.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for stainless steel mechanical penetrations or spent fuel pool liners that are embedded/encased in concrete.

The staff found that the applicant had identified an appropriate course of action to manage aging of stainless steel submerged surfaces of spent fuel pool liners because it is consistent with the guidance in the GALL Report. For other stainless steel structural components embedded/encased in concrete, the staff accepted the applicant’s AMR results that aging management is not required, because stainless steel structural components in general are not susceptible to degradation, and concrete provides protection for embedded/encased steel.

The staff’s review of LRA Table 3.5.2.2 identified areas in which additional information was necessary to complete the review of the applicant’s results. The applicant responded to the staff’s RAIs as discussed below.

In RAI 3.5-7, dated December 10, 2004, the staff stated that the buried environment item in LRA Table 3.0.2 states that ground water is non-aggressive. Therefore, the staff requested that the applicant provide historical site ground water chemistry test results together with a discussion of the extent of past ground water sampling and testing frequency, as well as the extent of fluctuation of the test results to support the above assertion.

In its response, by letter dated January 31, 2005, the applicant stated:

> Since BFN did not have data available from the construction period or since plant start-up, baseline sampling was performed over the past year of groundwater and the Wheeler Reservoir. The baseline sampling was to establish if BFN had aggressive or non-aggressive water as defined by the following criteria: pH <5.5, Chlorides > 500 ppm and Sulfates > 1500 ppm. The samples were taken at intervals to take into consideration seasonal variations. The samples were taken from the existing site radiological monitoring wells and from the Wheeler Reservoir in close proximity to the Intake Pumping Station structure. Samples were taken at various depths in the monitoring well and the Reservoir by the site environment staff and analyzed by an off-site laboratory for the site environment group. Results of Browns Ferry groundwater and Wheeler Reservoir water sampling are as follows:
>
> a. Groundwater:
>
> - pH ranges from 6.33 to 8.77 which are well above <5.5 (Note in the well that the value 6.33 was obtained, the remaining pH readings ranged from 7.16 to 7.60 during the time period of sampling. Only one other well had a pH value below 7 and its pH was 6.92 with the remaining readings ranging between 7.12 and 7.6)
> - Chlorides – maximum reading of 18.3 ppm which is well below the threshold of 500 ppm
> - Sulfates–maximum reading of 30.3 ppm which is well below the threshold of 1500 ppm
>
> b. Wheeler Reservoir:
>
> - pH ranges from 7.28 to 8.64 which are well above < 5.5
> - Chlorides – maximum reading of 13.9 ppm which is well below the threshold of 500 ppm
> - Sulfates – maximum reading of 15.5 ppm which is well below the threshold of 1500 ppm
>
> Browns Ferry groundwater and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (i.e., an aggressive environment does not exist).

Based on the above test data, the staff found that both the Browns Ferry groundwater and the Wheeler Reservoir water are non-aggressive. Therefore, the staff's concern described in RAI 3.5-7 is resolved.

In RAI 3.5-8, dated December 10, 2004, the staff stated that the AMR discussion provided in LRA Section 3.5.2.2.2.2 is rather general and brief, and requires more detailed elaboration to support BFN's conclusion that the conditions identified in the GALL Report, as revised by ISG-03, are satisfied and no aging management for below-grade inaccessible concrete is needed. Therefore, the staff requested that the applicant provide additional specific information, including: (1) concrete quality and test data for inaccessible concrete, (2) past operating experience regarding exposure of inaccessible concrete to aggressive chemical/fluid environment, and (3) past inaccessible concrete inspection findings and data related to concrete degradation and repairs.

In its response, by letter dated January 31, 2005, the applicant stated:

(1) The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

(2) As noted in the response to RAI 3.5-7, Browns Ferry groundwater water and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist).

(3) A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects when below-grade inaccessible concrete was excavated for other reasons.

Based on the plant-specific operating experience reported in item 3 and the fact that the applicant complied with applicable provisions of the GALL Report, the staff found the applicant's response acceptable, and the staff's concern described in RAI 3.5-8 is resolved.

In RAI 3.5-9, dated December 10, 2004, the staff stated that in LRA Table 3.5.2.2, no AERM and AMPs are identified for hatches/plugs, and electrical and instrumentation and control (I&C) penetrations made of carbon and low-alloy steel that are embedded or encased in concrete; whereas, GALL Report Item III.A2.2-a calls for a Structures Monitoring Program to manage the loss of material and corrosion aging effects for steel components exposed to various environments. Additionally, the mechanical penetrations listed in Table 3.5.2.2 and the structural steel beams, columns, plates, and trusses that are embedded or encased in concrete are also identified as having no applicable aging effect that requires aging management; therefore, no AMP is designated for the components. This same BFN position is shown throughout the remainder of LRA Table 3.5.2.2. Therefore, the staff requested the applicant to discuss past operating experience and inspection results related to aging degradation of embedded or encased hatches, plugs, duct banks, manholes, mechanical penetrations, and electrical and I&C penetrations in order to provide an operating experience-based rationale to justify its assertion that these components require no AMP to manage their aging.

In its response, by letter dated January 31, 2005, the applicant stated:

> The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability

concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.

> Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77. As a minimum, all exposed portions of embedded carbon steel structural components are inspected for the following aging effects:
>
> - Outside Air Environments: Loss of material due to general and pitting corrosion
> - Inside Air Environments: Loss of material due to general corrosion
> - Containment Air Environments: Loss of material due to general corrosion
>
> A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for carbon steel components embedded/encased in concrete.

Based on the above plant-specific operating experience and the fact that concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete, the staff found that the applicant had adequately justified its AMR results regarding the concrete elements listed in LRA Table 3.5.2.2. Therefore, the staff's concern described in RAI 3.5-9 is resolved.

In RAI 3.5-10, dated December 10, 2004, the staff noted that non-ferrous aluminum electrical and I&C penetrations embedded or encased in concrete are listed in the second item of LRA Table 3.5.2.2 as components requiring no AMP to manage any aging effect. Therefore, the staff requested the applicant to provide a discussion of past and applicable industry operating experience to justify this AMR finding. Additionally, referring to embedded or encased stainless steel spent fuel pool liners listed in LRA Table 3.5.2.2, the applicant was requested to discuss applicable operating experience of these liners to justify its AMR results that no AMP is needed to manage any aging effect.

In its response, by letter dated January 31, 2005, the applicant stated:

> The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.
>
> Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.
>
> <u>Embedded or Encased Aluminum Response</u>: Aluminum is a reactive metal, but it develops an aluminum oxide film that protects it from further corrosion in an indoor

environment. The specific aluminum alloy (6063-T42) used at BFN for conduit and raceways is resistant to general corrosion, pitting, and SCC during testing in outdoor, and saltwater environments. For the aluminum that is embedded/encased within the concrete, corrosion is not considered an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and potentially allow for the intrusion of aggressive ions causing a reduction in concrete pH. Aging management of concrete aging effects will manage the corrosion of the embedded/encased aluminum's concrete protective cover. A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for aluminum components embedded/encased in concrete.

<u>Embedded or Encased Stainless Steel Response</u>: For the stainless steel that is embedded/encased within the concrete, corrosion is similarly not considered an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and allow for the intrusion of aggressive ions causing a reduction in concrete pH. Adequate management of other concrete aging effects will in effect manage the aging of the embedded/encased stainless steel. After a review of the Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for stainless steel that is embedded/encased within concrete. Operating history did show a small leak in the Unit 1 fuel pool liner. The Unit 1 fuel pool has remained in service during the extended outage since spent fuel is stored in the pool. This leak in the Unit 1 fuel pool was documented in accordance with the site's Corrective Action Program, SPP-3.1, Tennessee Valley Authority Nuclear (TVAN) Standard Program and Processes, "Corrective Action Program" as PER 00- 011982-000 (electronic corrective action program number 35486. This leak is contained within the leak channel beneath the fuel pool liner). The fuel pool liners are monitored on a monthly basis per operation instruction 1-OI-78. The leak is small (~0.06 gpm) and has been steady over time without an increasing trend over the last ten years.

The staff found the above applicant's justification reasonable and adequate because it was supported by the fact that the operating history, structures monitoring baseline inspection, and results from the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for aluminum and stainless steel embedded or encased within concrete. Therefore, the staff's concerns described in RAI 3.5-10 are resolved.

In RAI 3.5-14, dated December 10, 2004, the staff stated that, with respect to the neutron-absorbing sheets in spent fuel storage racks, as described in LRA Section 3.3.2.2, the applicant stated that the Chemistry Control Program manages general corrosion and that an inspection of Boral coupon test specimens was performed at BFN that confirmed that no significant aging degradation had occurred and that the neutron-absorbing capacity of the Boral had not been reduced. Since it is implied that some Boral aging degradations had occurred at the time of inspection of the test specimens, the staff requested the applicant to discuss the basis for the above assertion that the neutron-absorbing capacity of the Boral will be maintained at an adequate level during the extended period of plant operation.

In its response, by letter dated January 31, 2005, the applicant stated:

> A total of 16 boral coupons were placed in the Unit 3 spent fuel storage pool (SFSP) in October 1983. The coupons supplied by the rack manufacturer are of the same metallurgical condition as the high density fuel storage racks (HDFSR) in thickness, chemistry, finish, and temper. For the first six years of the planned fifteen year surveillance program, examination was to have taken place at two-year intervals. Accordingly, two coupons were removed in October 1985. Blisters were found upon examination, and because of this unexpected anomaly, three additional coupons were analyzed not finding any blisters. As a result of blisters found on the coupons removed in 1985, the surveillance program has been expanded to include monitoring the formation and behavior of these blisters. These boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. Also, a metallurgical engineer examines the coupons for general corrosion, local pitting, and bonding. No further blisters, corrosion, or degradation has been identified in coupons evaluated through 2003.

The above response states that these Boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. The response also implies that a metallurgical engineer periodically examines the coupons for general corrosion, local pitting, and bonding. Also, no further blisters, corrosion, or degradation have been identified in coupons evaluated through 2003; however, it was not clear to the staff whether these periodic inspections are ongoing activities that are an extension of the 1983 Boral Coupon Inspection Program covering Boral coupon test specimens or a separate AMP in addition to the Chemistry Control Program mentioned above. The applicant was requested to clarify the key parameters of this periodic inspection program or activity including the objective, scope, frequency, and inspection approach of the program.

In its response, by letter May 24, 2005, the applicant stated that:

> The Boral coupon inspection program was initiated in 1983 to implement the inspection and testing requirements of UFSAR Section 10.3.6; this checks the long-term behavior of the material of the high density spent fuel racks. The inspection is performed per BFN Technical Instruction (TI) TI-116, “High Density Fuel Storage System Surveillance Program.” When the TI is performed, Boral coupons are removed from the spent fuel storage pool and examined by the Metallurgical Engineer in their original condition to determine if sampling of surface corrosion products is appropriate. Thickness measurements are obtained of each coupon and documented in accordance with the TI. If degradation is such that further investigation is warranted, a minimum of one coupon is selected to be unsheathed or opened. Prior to the unsheathing process, a dye penetrant test for indications on the outer surfaces of the coupon will be performed and is examined by the Metallurgical Engineer. The Metallurgical Engineer decides if further unsheathing of the coupons is required. The visual examination by the Metallurgical Engineer is documented on the appropriate forms of the TI. The current frequency for

> performing this TI is two years. The surveillance frequency is re-evaluated each time the surveillance is performed and can be changed based on the trend of the historical data results. The inspection of the Boral coupons will continue until such time as the trend of the historical data results collected provides a basis to discontinue the inspections.

Based on its review, the staff found the applicant's response to RAI 3.5-14 acceptable. Therefore, the staff's concern described in RAI 3.5-14 is resolved.

In RAI 4.7.4-1, dated December 10, 2004, LRA Table 3.5.2.2 lists the AMR results of expansion joint (elastomer, polyurethane foam) as a TLAA and refers the TLAA to LRA Section 4.7. LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam," states that an analysis of the effect of dose on the foam showed the material properties will remain within the limits assumed by the original design analysis for the additional 20 years of extended operation. Therefore, the staff requested the applicant to provide a more detailed discussion of the analysis including a discussion of the assumptions adopted in the analysis, the type of data extrapolation applied, and the quantitative results obtained to justify the assertion that the requirements of 10 CFR 54.21(c)(1)(i) are fully met.

By letter dated January 31, 2005, the applicant provided its response to RAI 4.7.4-1. The staff evaluation of the applicant's response is provided in SER Section 4.7.4.

In RAI 3.5-17, dated March 25, 2005, the staff stated that LRA Table 3.5.2.29, Radwaste Building, has three separate rows of component type listings (i.e., reinforced concrete, beams, column, walls, and slabs) which make references to note I,1 (last column of the table) and are shown to be associated with NUREG-1801 Section III.A3.1-h, Volume 2. Note I,1 of the table implies that the radwaste building is founded on rock or bearing piles. The note also refers to LRA Section 3.5.2.2.2.1 for further evaluation. Item 5 of the section does not clearly indicate that the radwaste building is founded on rock or bearing piles. Therefore, the staff requested that the applicant provide the type of foundation medium that supports the building; and if the structure is not founded on rock or piles, to discuss the basis for asserting that the cracking, distortion, and increase in component stress level due to settlement are not aging effects requiring management. The applicant was also asked, as appropriate, to revise LRA Sections 3.5.2.1 and 3.5.2.2.2.1 to include the radwaste building within the scope of its discussion.

In its response, by letter April 14, 2005, the applicant stated:

> The Radwaste Building is founded on piles as noted by the entry under "Component Type" - "Piles" in Table 2.4.7.8.
>
> LRA Section 3.5.2.2.2.1, Item 5, paragraph 1 on page 3.5-43 should be revised to read:
>
>> "Cracks, distortion, increase in component stress level due to settlement are not considered as aging effects requiring management for BFN structures founded on rock or bearing piles. The following BFN structures are founded on rock or bearing piles: Reactor Buildings, Primary Containments, Intake Pumping Station, Reinforced Concrete Chimney, Off-Gas Treatment Building, Equipment Access Lock, Turbine Buildings, Gate Structure Number 3, Diesel HPFP House, Transformer Yard, RHRSW Tunnel and Radwaste Building. Based on industry

experience, settlement of Class 1 structures founded on bedrock or bearing piles have not been noted to cause aging effects requiring management."

Based on its review, the staff found the applicant's response to RAI 3.5-17 acceptable. Therefore, the staff's concern described in RAI 3.5-17 is resolved.

In RAI 3.5-18, dated March 25, 2005, the staff stated that in its review of LRA Table 3.5.2.30, it was not clear as to whether the Group 5 category referred to includes the service building. Therefore, the staff requested that the applicant confirm that the service building, or portion of the service building, is clearly included within the scope addressed by LRA Section 3.5.2.2.2.1 and make any necessary revision to the LRA section to clarify its position.

In its response, by letter dated April 14, 2005, the applicant stated:

> The aging management review of the Service Building was performed to the requirements for Group 3 Structures of NUREG-1801, Vol. 2, Chapter III.A3. The Service Building is included within the scope addressed by LRA Section 3.5.2.2.2.1, Item 8 since it was considered as a Group 3 Structure and that section is applicable to Group 1 through Group 5 Structures of NUREG-1801, Vol. 2 Chapter 3.

The staff found the above response acceptable. Therefore, the staff's concern described in RAI 3.5-18 is resolved.

The staff also reviewed the information provided in LRA Section 3.5.2.1.2 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the reactor buildings' components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the service building components acceptable.

3.5.2.3.3 Equipment Access Lock – Summary of Aging Management Evaluation – Table 3.5.2.3

The staff reviewed LRA Table 3.5.2.3, which summarizes the results of AMR evaluations for the equipment access lock component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.3 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the equipment access lock components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the equipment access lock components acceptable.

3.5.2.3.4 Earth Berm – Summary of Aging Management Evaluation – Table 3.5.2.4

The staff reviewed LRA Table 3.5.2.4, which summarizes the results of AMR evaluations for the earth berm component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.4 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the earth berm components that are not addressed by the

GALL Report. The staff found the applicant's AMR results for the earth berm components acceptable.

3.5.2.3.5 Diesel Generator Buildings – Summary of Aging Management Evaluation – Table 3.5.2.5

The staff reviewed LRA Table 3.5.2.5, which summarizes the results of AMR evaluations for the diesel generator buildings component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.25, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Ceramic Fiber in an Inside Air Environment</u> - The staff requested that the applicant provide the BFN technical basis for concluding that no aging management is required for ceramic fiber fire barriers in an inside air environment.

The following list identifies ceramic fiber components in an inside air environment:

- reactor building fire barriers
- diesel generator building fire barriers

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that ceramic and glass fiber used to seal fire barrier penetrations do not have any applicable aging effects requiring aging management. This is consistent with previous staff positions in LRA SER concurrences that there are no applicable aging effects for glass used in a metal fire barrier penetration. This is also consistent with the NUREG-1769 SER related to the license renewal of another plant which concurred that insulation made of aluminum, stainless steel (mirror), calcium silicate, ceramic fiber, or fiberglass in a sheltered environment does not have any aging effects requiring aging management.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following ceramic fiber components.

- reactor building fire barriers
- diesel generator building fire barriers

The staff concluded that the applicant had not credited an existing AMP (structures monitoring and/or fire protection) that already included fire barriers in its scope on the basis that its AMR did not identify any applicable aging effects.

The staff's review of LRA Table 3.5.2.5 identified an area in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI, as discussed below.

In RAI 3.5-11, dated December 10, 2004, the staff stated that, with respect to the fire barriers consisting of ceramic fiber listed in LRA Table 3.5.2.5, the applicant's AMR identified neither AERM nor AMP for the ceramic fiber fire barriers. Therefore, the staff requested that the applicant discuss past plant-specific inspection results of these fire barriers in order to provide an operating experience-based justification for the above AMR finding.

In its response, by letter dated January 31, 2005, the applicant stated:

> This same RAI was asked as RAI 3.3-2 for the Reactor Building. In the response to that RAI, the same material was also addressed for the Diesel Generator Building (Table 3.5.2.5, item number 10 on page 3.5-74). Refer to the TVA response to RAI 3.3-2 (TVA letter to NRC dated September 30, 2004).

The staff found the response to RAI 3.5-11 provided in SER Section 3.3 acceptable; therefore, the staff's concern expressed in RAI 3.5-11 is resolved.

The staff also reviewed the information provided in LRA Section 3.5.2.1.5 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the diesel generator buildings' components that are not addressed by the GALL Report. The staff found the applicant's AMR results for diesel generator buildings' components acceptable.

3.5.2.3.6 Standby Gas Treatment Building – Summary of Aging Management Evaluation – Table 3.5.2.6

The staff reviewed LRA Table 3.5.2.6, which summarizes the results of AMR evaluations for the standby gas treatment building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.6 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the standby gas treatment building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the standby gas treatment building components acceptable.

3.5.2.3.7 Off-Gas Treatment Building – Summary of Aging Management Evaluation – Table 3.5.2.7

The staff reviewed LRA Table 3.5.2.7, which summarizes the results of AMR evaluations for the off-gas treatment building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.7 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the off-gas treatment building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the off-gas treatment building components acceptable.

3.5.2.3.8 Vacuum Pipe Building – Summary of Aging Management Evaluation – Table 3.5.2.8

The staff reviewed LRA Table 3.5.2.8, which summarizes the results of AMR evaluations for the vacuum pipe building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.8 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the vacuum pipe building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the vacuum pipe building components acceptable.

3.5.2.3.9 Residual Heat Removal Service Water Tunnels – Summary of Aging Management Evaluation – Table 3.5.2.9

The staff reviewed LRA Table 3.5.2.9, which summarizes the results of AMR evaluations for the RHRSW tunnels' component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.9 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the RHRSW tunnel components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the RHRSW tunnel components acceptable.

3.5.2.3.10 Electrical Cable Tunnel from Intake Pumping Station to the Powerhouse – Summary of Aging Management Evaluation – Table 3.5.2.10

The staff reviewed LRA Table 3.5.2.10, which summarizes the results of AMR evaluations for the electrical cable tunnel from intake pumping station to the powerhouse component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.10 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the electrical cable tunnel from the intake pumping station to the powerhouse components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the electrical cable tunnel from the intake pumping station to the powerhouse components acceptable.

3.5.2.3.11 Underground Concrete Encased Structures – Summary of Aging Management Evaluation – Table 3.5.2.11

The staff reviewed LRA Table 3.5.2.11, which summarizes the results of AMR evaluations for the underground concrete-encased structures component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.11 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the underground concrete-encased structures components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the underground concrete encased structures' components acceptable.

3.5.2.3.12 Intake Pumping Station – Summary of Aging Management Evaluation – Table 3.5.2.12

The staff reviewed LRA Table 3.5.2.12, which summarizes the results of AMR evaluations for the intake pumping station component groups.

In LRA Table 3.5.2.12, the applicant stated that no aging management is required for submerged reinforced concrete. Plant-specific Note 5 states that for cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel in concrete for inaccessible areas, no plant-specific aging management is required. Plant-specific Note 6 states that, for increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack of concrete for inaccessible areas, no plant-specific aging management is required.

During the onsite audit, the staff reviewed other selected items in LRA Table 3.5.2.12, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Reinforced Concrete in a Submerged Environment</u> - In LRA Table 3.5.2.12 (Intake Pumping Station - Summary of Aging Management Evaluation), rows 37 and 38, the applicant stated that no aging management is required for submerged reinforced concrete. Note 5 for row 37 states that for cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel in concrete for inaccessible areas, no plant-specific aging management is required. Note 6 for row 38 states that for increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack of concrete for inaccessible areas, no plant-specific aging is required.

The staff noted that a submerged component is not necessarily inaccessible. If the submerged component is accessible, it is expected that the component will be managed by the Inspection of Water Control Structures Program. The staff requested that the applicant identify all the submerged concrete components in the intake pumping station, and provide the technical basis for designating these components as being inaccessible. The staff also requested that the applicant identify all the submerged concrete structures that will be inspected under Water Control Structures Program, and describe the implementing details of the inspection of submerged structures included in the Water Control Structures Program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that:

> Browns Ferry groundwater water and Wheeler Reservoir water sample measurements presented in the response to question 297 have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist). It is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Browns Ferry. A change in the environment due to a chemical release would be considered as an “abnormal event”. NUREG-1800, “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,” states that aging effects from abnormal events need not be postulated specifically for license renewal.

In-scope submerged concrete exposed to Wheeler Reservoir water is not readily accessible for inspection. Several in-scope submerged concrete common areas outside of individual pump bays where continuous flow make diver entry unsafe would require a multiple unit outage to inspect. Browns Ferry will perform a one time inspection of the in-scope submerged concrete in one individual pump bay to confirm the absence of aggressive environmental aging effects and that a loss of intended function has not occurred due to aggressive environment aging effects.

Browns Ferry will also continue to perform periodic inspections of accessible concrete in an inside air environment and outside air environment for in-scope structures with the Structures Monitoring Program.

The staff concluded that the applicant's AMR is not consistent with the GALL Report and is not acceptable, because there is no commitment to conduct periodic inspection of accessible, submerged water control concrete structures. This issue was addressed in RAI 3.5-16 and is discussed below.

In RAI 3.5-16, dated March 11, 2005, the staff requested the applicant to demonstrate that the groundwater is not an aggressive environment, although the facts show that an aggressive environment does not exist for groundwater, and continuous water flow in several in-scope submerged concrete common areas outside of individual pump bays makes diver entry unsafe. Therefore, the staff requested that the applicant provide the following additional information and a plant-specific commitment, as needed, in order to expedite staff closure of the issue raised by the audit team:

(1) A discussion of past inspection findings, and repairs and maintenance experience for submerged, reinforced concrete structures (e.g., intake structure).

(2) A discussion of the pertinent submerged, reinforced concrete test data (as available) which demonstrate that the conditions stated in the discussion columns of items III A6.1-b and III A6.1-d in GALL Report, Volume II, are fully met.

(3) A detailed description of the one-time inspection by the applicant, cited above, of the in-scope submerged concrete in one individual pump bay, including method of inspection; concrete elements and parameters or types of degradation to be inspected; criteria for judging the observed types, extent, and severity of reinforced concrete degradation that would trigger BFN's commitment to an AMP for submerged concrete with a periodic inspection provision, inspection frequency, and schedule for implementing the One-Time Inspection Program.

(4) A discussion of the methods (e.g., regular monitoring of the raw water for pH, chloride concentration, sulfate concentration, abrasive particulates, detrimental organic agents) that will be employed to ensure that the raw service water in close proximity to the intake structure remains non-aggressive to the submerged concrete during the extended period of operation.

In its response, by letter dated April 5, 2005, the applicant stated:

(1) BFN's submerged concrete operating experience:

A baseline inspection for the BFN Structures Monitoring Program was established in 1997 and included the Intake Pumping Station and Gate Structure No. 3. Baseline inspections and subsequent BFN Structures Monitoring Program inspections included accessible interior and exterior concrete surfaces of the Intake Pumping Station and Gate Structure No. 3. Only the Intake Pumping Station has submerged concrete that is in the scope of license renewal. Although the Intake Pumping Station submerged concrete was not inspected, there is reasonable assurance that the submerged concrete results would be consistent due to a lack of an aggressive environment and use of the same concrete specifications for the construction as the accessible portions of the Intake Pumping Station.

Defect evaluations performed since the baseline inspection and subsequent inspections are documented in the 2002 Structures Monitoring Program results. Below is a highlight of plant-specific operating experience for concrete elements at the Intake Pumping Station and Gate Structure No. 3. None of the identified indications were considered significant or affected the function of the structure.

- Intake Pumping Station: Very minor concrete surface cracks
- Gate Structure No. 3: Very minor concrete surface cracks and spalling

Additionally, to capture plant operating experience for these structures, work orders (WOs), the site Correction Action Program and site Licensing Event Reports (LERs) were reviewed for various operating periods:

- Work Orders between 1991 and 2004 were reviewed to determine if any corrective maintenance or repairs were performed on the Intake Pumping Station (IPS). A total of 2633 WOs were reviewed for that period and no work activities were found involving the submerged concrete for this structure.
- The site’s Correction Action Program was reviewed for the IPS to identify any adverse conditions of the structure, with emphasis on the submerged concrete. A total of 1790 reports were reviewed for a time period between 1994 and 2004, with none being identified for the IPS submerged concrete.
- Licensing Event Reports were reviewed for a period between 1985 and 2004 and none were identified affecting the IPS.

(2) GALL conditions for III A6.1-b (increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide)& III A6.1-d (cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel):

See further evaluations in LRA Section 3.5.2.2.2.1, item 2 and LRA Section 3.5.2.2.2.2 for discussion on these issues.

(3) Submerged concrete one-time inspection:

The following elements apply to the one-time inspection for submerged concrete:

a. Scope of One-Time Inspection:

In-scope submerged concrete in one individual pump bay of the Intake Pumping Station. The submerged concrete surfaces will be inspected.

b. Preventative Measures:

The one-time inspection specifies no preventive actions.

c. Parameters Monitored or Inspected:

The following concrete aging effects will be inspected during the one-time inspection of submerged concrete at the intake pumping station (IPS).

- Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide
- Expansion and cracking due to reaction with aggregates
- Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack

The Intake Pumping Station will be periodically inspected for loss of material (spalling, scaling)and cracking due to the effects of freeze-thaw at the waterline where icing conditions could occur(see GALL audit question 368). The periodic inspection for aging effects due to freeze thaw will be included in the BFN Structures Monitoring Program.

d. Detection of Aging Effects:

Visual inspections of structural conditions will be used as the method used to detect aging effects. An inspection checklist consistent with those used for Structures Monitoring Program will be used. All defects will be required to be identified and documented on the inspection checklists for review and evaluation by the Responsible Engineer (BFN Structures Monitoring Program Engineer). Individuals trained and experienced with the BFN Structures Monitoring Program will perform the inspections.

e. Monitoring and Trending:

The submerged concrete at the Intake Pumping Station will be inspected prior to the extended period of operation.

f. The acceptance criteria of the BFN Structures Monitoring Program will be used. BFN Structures Monitoring Program acceptance criteria are based upon Responsible Engineer (BFN Structures Monitoring Program Engineer) review and classification of the results as acceptable, acceptable with deficiencies, and unacceptable respectively. These performance criteria ensure that the structure:

- remains capable of meeting its design basis and performing its intended function; and
- will not result in a loss of intended function due to a degraded condition or aging effect.

If the submerged concrete fails to meet the acceptance criteria, a cause determination evaluation will be performed. If acceptance criteria are not meet, two additional pump bays will be inspected prior to the extended period of operation. If one or more of the additional pump bays fails to meet its acceptance criteria, then submerged concrete at the intake pump station will be inspected periodically consistent with the Structures Monitoring Program requirements.

(4) Periodic monitoring of raw service water:

Prior to entering the period of extended operation, BFN will initiate periodic monitoring of the raw service water in close proximity to the Intake Pumping Station for the requirements of an aggressive environment as described in NUREG-1557. Periodic monitoring will be consistent with the BFN Structures Monitoring Program inspection frequency.

The staff reviewed the above response and found that the applicant fully had responded to RAI 3.5-16 with reasonable plant operation-based justifications. Therefore, the staff's concern described in RAI 3.5-16 is resolved.

<u>Aluminum in an Outside Air Environment</u> – The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum components is required for an outside environment.

The following list identifies aluminum components in an outside air environment:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum alloys containing zinc are susceptible to corrosion in wetted, aggressive environments. The outside air environment does not have contaminants that would cause an aggressive environment. Additionally, rain would periodically wash any contaminant(s) from the material. The aluminum penetration sleeves and conduit at BFN are also constructed of 6063-T42 alloy material that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Therefore, the potential for concentration of contaminates is not significant for aluminum components in an outside air environment and loss of function due to corrosion is not considered plausible.

The applicant also stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)," EPRI 1002950 revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in a non-aggressive ambient outside environment (general, galvanic, crevice and pitting corrosion, and SCC).

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following aluminum components:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

The staff accepts the applicant's AMR results, that aging management is not required for these aluminum components in an outside environment, on the basis that (1) the material used is resistant to corrosion and SCC, and (2) concentration of contaminates in a non-aggressive ambient outside environment is not plausible

The staff also reviewed the information provided in LRA Section 3.5.2.~~1~~.12 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the intake pumping station components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the intake pumping station components acceptable.

3.5.2.3.13 Gate Structure No. 3 – Summary of Aging Management Evaluation – Table 3.5.2.13

The staff reviewed LRA Table 3.5.2.13, which summarizes the results of AMR evaluations for the gate structure No. 3 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.13 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the gate structure No. 3 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the gate structure No. 3 components acceptable.

3.5.2.3.14 Intake Channel – Summary of Aging Management Evaluation – Table 3.5.2.14

The staff reviewed LRA Table 3.5.2.14, which summarizes the results of AMR evaluations for the intake channel component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.14 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the intake channel components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the intake channel components acceptable.

3.5.2.3.15 North Bank of Cool Water Channel East of Gate Structure No. 2 – Summary of Aging Management Evaluation – Table 3.5.2.15

The staff reviewed LRA Table 3.5.2.15, which summarizes the results of AMR evaluations for the north bank of cool water channel east of gate structure No. 2 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.15 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the north bank of cool water channel east of gate structure No. 2 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the north bank of cool water channel east of gate structure No. 2 components acceptable.

3.5.2.3.16 South Dike of Cool Water Channel Between Gate Structure Nos. 2 and 3 – Summary of Aging Management Evaluation – Table 3.5.2.16

The staff reviewed LRA Table 3.5.2.16, which summarizes the results of AMR evaluations for the south dike of cool water channel between gate structure Nos. 2 and 3 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.16 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the south dike of the cool water channel between gate structure Nos. 2 and 3 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the south dike of the cool water channel between gate structure Nos. 2 and 3 components acceptable.

3.5.2.3.17 Condensate Water Storage Tanks' Foundations and Trenches – Summary of Aging Management Evaluation – Table 3.5.2.17

The staff reviewed LRA Table 3.5.2.17, which summarizes the results of AMR evaluations for the condensate water storage tanks' foundations and trenches component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.17, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 item:

<u>Earthfill & Rock in a Buried Environment</u> - This item indicates that the equipment supports and foundations are earth fill (rock and sand). The staff requested that the applicant explain the technical bases for concluding that there are no aging effects requiring management.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the foundation for the CWST is comprised of a concrete ring foundation with the interior portion of the ring foundation filled with crushed rock and sand. The earthen materials (rock and sand) of the CWST foundation interior base are protected from environmental weathering conditions by the concrete perimeter ring and CWST tank bottom. There are no aging effects for the earthen materials of the CWST foundation interior base that require aging management. Aging management of the CWST concrete foundation ring is managed by the Structures Monitoring Program. Aging management of the CWST bottom will be performed by the One-Time Inspection Program.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for earthen materials of the CWST foundation interior base.

Based on the additional information provided by the applicant, the staff concurs with the applicant's AMR results for the crushed rock and sand base of the CWST. The staff concluded that aging management is not required because these materials are adequately protected by the concrete perimeter ring and the CWST tank bottom.

The staff also reviewed the information provided in LRA Section 3.5.2.1.17 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the condensate water storage tanks' foundations and trenches components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the condensate water storage tanks' foundations and trenches components acceptable.

3.5.2.3.18 Containment Atmosphere Dilution Storage Tanks' Foundations – Summary of Aging Management Evaluation – Table 3.5.2.18

The staff reviewed LRA Table 3.5.2.18, which summarizes the results of AMR evaluations for the containment atmosphere dilution storage tanks' foundations component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.18 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the containment atmosphere dilution storage tanks' foundations components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the containment atmosphere dilution storage tanks' foundations components acceptable.

3.5.2.3.19 Reinforced Concrete Chimney – Summary of Aging Management Evaluation – Table 3.5.2.19

The staff reviewed LRA Table 3.5.2.19, which summarizes the results of AMR evaluations for the reinforced concrete chimney component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.19 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Carbon Steel in a Buried Environment- The applicant stated that the Structures Monitoring Program relies on visual inspections whenever the components are uncovered during station yard area excavations. The staff requested that the applicant confirm that this applies to buried mechanical penetrations, clarify what other components are included in this provision, and explain whether this is an enhancement to the existing program or whether this provision is covered in the current program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LCEI-CI-C9 will be enhanced to include inspection of mechanical penetrations when accessible. There are no other buried carbon steel components included with the program; however, LCEI-CI-C9 will also be enhanced to include the inspection of buried concrete when accessible. With enhancements, LCEI-CI-C9 will be consistent with GALL AMP XI.S6.

The applicant also stated that the Buried Piping and Tanks Inspections Program provides the inspection requirements of buried piping when accessible. The Buried Piping and Tanks Inspections Program is consistent with GALL AMP XI.M34. Section 7.2.9.2 of LCEI-CI-C9 currently provides the inspection attributes of buried piping, which includes pipe connections and joints, and is credited as the Buried Piping and Tanks Inspections Program.

The staff concluded that the applicant's commitment to enhance the Structures Monitoring Program to include inspection of buried mechanical penetrations when accessible, provides a level of aging management for buried mechanical penetrations that is comparable to the GALL Report recommendations for buried concrete, piping and tanks. Therefore, the staff found this acceptable.

The staff also reviewed the information provided in LRA Section 3.5.2.1.19 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the reinforced concrete chimney components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the reinforced concrete chimney components acceptable.

3.5.2.3.20 Turbine Buildings – Summary of Aging Management Evaluation – Table 3.5.2.20

The staff reviewed LRA Table 3.5.2.20, which summarizes the results of AMR evaluations for the turbine buildings component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.20 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the turbine buildings components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the turbine buildings components acceptable.

3.5.2.3.21 Diesel High Pressure Fire Pump House – Summary of Aging Management Evaluation – Table 3.5.2.21

The staff reviewed LRA Table 3.5.2.21, which summarizes the results of AMR evaluations for the diesel high-pressure fire pump house component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.21 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 item:

<u>Stainless Steel in a Submerged Environment</u> - This item credits the Structures Monitoring Program for managing the effects of loss of material due to crevice corrosion and pitting corrosion for stainless steel beams, columns, plates, and trusses in a submerged environment. The staff requested the applicant to identify (1) the components included in this item and (2) where they are located, and (3) the submerged environment. A description of the types of inspections that will be performed under the Structures Monitoring Program for these components and clarification on whether these inspections are included in the current scope of the Structures Monitoring Program was also requested. The staff also requested the applicant to provide the technical basis for not monitoring water chemistry.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.21 row 28 applies to submerged portions of the stainless steel debris screen under the diesel high pressure fire pump house. The intended functions of the debris screen are debris protection and NSR structural support. The applicant also stated that the miscellaneous components portion of the Structures Monitoring Program will be enhanced to visually inspect the submerged portions of the debris screen for loss of material due to crevice and pitting corrosion. The applicant noted that portions of the diesel high-pressure fire pump house debris screen are submerged in a raw water environment; therefore, monitoring of water chemistry is not applicable as an AMP.

The staff accepts the applicant's commitment to enhance the Structures Monitoring Program to visually inspect the submerged portions of the stainless steel debris screen for loss of material due to crevice and pitting corrosion. The staff considered this to be analogous to submerged portions of water control structures for which visual inspection conducted as part of the Structures Monitoring Program has been previously accepted.

The staff also reviewed the information provided in LRA Section 3.5.2.1.21 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the diesel high-pressure fire pump house components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the diesel high-pressure fire pump house components acceptable.

3.5.2.3.22 Vent Vaults – Summary of Aging Management Evaluation – Table 3.5.2.22

The staff reviewed LRA Table 3.5.2.22, which summarizes the results of AMR evaluations for the vent vaults component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.22 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the vent vaults components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the vent vaults components acceptable.

3.5.2.3.23 Transformer Yard – Summary of Aging Management Evaluation – Table 3.5.2.23

The staff reviewed LRA Table 3.5.2.23, which summarizes the results of AMR evaluations for the transformer yard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.23 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the transformer yard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the transformer yard components acceptable.

3.5.2.3.24 161 kV Switchyard – Summary of Aging Management Evaluation – Table 3.5.2.24

The staff reviewed LRA Table 3.5.2.24, which summarizes the results of AMR evaluations for the 161 kV switchyard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.24 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the 161 kV switchyard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the 161 kV switchyard components acceptable.

3.5.2.3.25 500 kV Switchyard – Summary of Aging Management Evaluation – Table 3.5.2.25

The staff reviewed LRA Table 3.5.2.25, which summarizes the results of AMR evaluations for the 500 kV Switchyard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.25 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the 500 kV switchyard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the 500 kV switchyard components acceptable.

3.5.2.3.26 Structures and Component Supports – Summary of Aging Management Evaluation – Table 3.5.2.26

The staff reviewed LRA Table 3.5.2.26, which summarizes the results of AMR evaluations for the structures and component supports component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.26 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Aluminum in an Inside Air Environment - The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum supports is required for loss of mechanical function in an inside air environment.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum in an inside air environment applies to aluminum pipe lugs for equivalent ASME Class 2 or 3 piping in the reactor buildings (inside air environment). Aluminum external surfaces are not susceptible to corrosion unless their surfaces are wetted and there is a potential for concentration of contaminants. The aluminum pipe lugs in the reactor building are not exposed to a wetted aggressive/corrosive environment. Therefore, the potential for concentration of contaminants is not significant for aluminum components in an inside air environment and loss of mechanical function due to corrosion is not considered plausible.

The applicant further stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)" EPRI 1002950 Revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in an inside environment (general, galvanic, crevice, pitting corrosion, and SCC).

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for aluminum pipe lugs for equivalent ASME Code Class 2 or 3 piping in the reactor buildings for an inside air environment.

The staff found that the applicant had not considered loss of mechanical function due to aging mechanisms other than corrosion. This omission is not consistent with the GALL Report. The applicant also failed to credit an existing AMP (IWF) that includes the subject components in its scope.The staff requested additional information to resolve this issue, and related issues. The disposition is discussed at the end of this section, as part of the review of LRA Table 3.5.2.26 AMRs.

The staff also reviewed the information provided in LRA Section 3.5.2.1.26 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the structures and component supports commodities components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the structures and component supports commodities components acceptable.

Aluminum in an Outside Air Environment – The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum components is required for an outside environment.

The following list identifies aluminum components in an outside air environment:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum alloys containing zinc are susceptible to corrosion in wetted aggressive environments. The outside air environment does not have contaminants that would cause an aggressive environment. Additionally, rain would periodically wash any contaminant(s) from the material. The aluminum penetration sleeves and conduit at BFN are also constructed of 6063-T42 alloy material that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Therefore, the potential for concentration of contaminates is not significant for aluminum components in an outside air environment and loss of function due to corrosion is not considered plausible.

The applicant also stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)" EPRI 1002950 Revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in a non-aggressive ambient outside environment (general, galvanic, crevice and pitting corrosion, and SCC).

The applicant further stated that a review of Browns Ferry operating history did not reveal any loss of intended function due to aging effects for the following aluminum components:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

The staff accepts the applicant's AMR results, that aging management is not required for these aluminum components in an outside environment, on the basis that (1) the material used is resistant to corrosion and SCC, and (2) concentration of contaminates in a non-aggressive ambient outside environment is not plausible

<u>Carbon Steel in a Containment Air Environment</u> – For the high-strength bolts included under this item, the staff requested that the applicant describe the bolting material, the nominal and as-built yield strengths, and the hardness of the material. The applicant was also requested to discuss the disposition of the recommendations for a comprehensive Bolting Integrity Program, as delineated in NUREG-1339, and industry recommendations, as delineated in EPRI NP-5769.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating:

> The only high strength structural bolting (ultimate tensile strength [UTS] > 150 ksi) material specified for use at BFN is ASTM A-490 (Ref. General Engineering Specification G-29BS01, PS 4.M.4.4, “ASME Section III and Non-ASME Section III (including AISC, ANSI B31.1, and ANSI B31.5) Bolting Material”). The ultimate tensile strength for A-490 bolting ½” to 1 ½” may vary between 150 to 170 ksi, a minimum yield strength of 130 ksi is specified and hardness may vary from 33 to 38 Rockwell C (ASTM A-490 Standard).
>
> The Bolting Integrity Program manages loss of material of mechanical component steel bolting within the scope of License Renewal. ASME Section XI manages aging of structural bolting (encompassed by ‘Support members; welds; bolted connections; support anchorage to building structure’) for ASME equivalent supports. Structures Monitoring Program manages aging of structural bolting for the remaining structural supports within the scope of License Renewal. The support components, including the bolting, are periodically inspected for loss of material by these programs.
>
> High strength bolting (UTS >150 ksi) is not considered susceptible to cracking due to stress corrosion cracking at BFN. For SCC to manifest in high strength bolting, an aggressive chemical or wetted environment is required in addition to susceptible material and high tensile stresses. High strength bolting (UTS >150 ksi) used in ASME equivalent supports at BFN are installed in indoor air environments that are not exposed to aggressive chemicals, periodic wetting, or splash zones. Additionally, high strength bolting is used for Unit 1 drywell floor steel framing and other structural purposes to connect the RPV skirt flange to the top flange of the ring girder in the drywell and these bolts are exposed to a containment atmosphere environment in the drywell not subject to aggressive chemicals, periodic wetting or splash zones. As noted below, thread lubricants are also controlled to eliminate corrosive environmental effects. Therefore an aggressive chemical or wetted environment does not exist.
>
> Per the EPRI Mechanical and Structural Tools and EPRI NP-5769, high strength bolting is considered susceptible to SCC in a corrosive environment with the use of thread lubricants containing molybdenum disulfide. Approved thread lubricants for use in bolted joints at BFN are specified in General Engineering Specification (GES) G-29B-S01 PS 4.M.1.1 and Section 3.9.2 notes that lubricants containing molybdenum disulfide shall not be used.
>
> Structural bolting procurement activities, receipt inspection and installation (torquing), as defined in TVA procedure GES G-29B-S01, P.S.4.M.4.4, ‘ASME Section III and Non-

Section III (Including AISC, ANSI B31.1, and ANSI B31.5) Bolting Material', are considered part of TVA's Bolting Integrity Program and meet the industry recommendations for these activities as delineated in NUREG-1339 and EPRI NP-5769.

The staff found that the applicant had presented a sufficient technical basis to support its AMR results that high-strength bolting used in structural applications is not susceptible to SCC. The staff determined that meeting the recommendations delineated in NUREG-1339 and EPRI NP-5769 provides reasonable assurance that SCC will not occur.

<u>Carbon Steel in an Inside Air Environment</u> - The applicant indicated that only loss of material due to general corrosion and loss of mechanical function due to corrosion are considered applicable aging effects for the subject ASME-equivalent supports. The staff requested the applicant to provide the technical basis for concluding that other aging mechanisms are not applicable.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26 row 2 applies to ASME-equivalent Class 1 supports. The AMR for the material and environment combination of carbon steel in an inside air environment was performed and the applicant concluded that the only plausible aging mechanisms needing managing were:

- loss of material due to general corrosion
- loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads

The applicant further stated that ASME Section XI, Subsection IWF will be used to manage these aging effects of loss of material and loss of mechanical function identified in Table 3.5.2.26 row 2. The staff found this acceptable, because it is consistent with GALL.

<u>Carbon Steel in an Outside Air Environment</u>– The applicant indicated that only loss of material due to general corrosion, crevice corrosion, and pitting corrosion are considered applicable aging effects for the subject ASME-equivalent supports. The staff requested the applicant to provide the technical basis for concluding that other aging mechanisms are not applicable.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 9 applies to ASME-equivalent Class 2 and 3 supports. The AMR for the material/environment combination of carbon steel in an outside air environment was performed and the applicant concluded that the only plausible aging mechanism that needed to be managed was loss of material due to general, crevice, and pitting corrosion.

The applicant further stated that the ASME Code Section XI, Subsection IWF will be used to manage the aging effect of loss of material identified in Table 3.5.2.26, row 9.

The staff noted that loss of mechanical function is also managed by IWF, even though the applicant did not identify this aging effect. The staff accepts the applicant's AMR results solely on the basis that IWF is credited for license renewal, and IWF will manage loss of mechanical function in addition to loss of material.

The applicant also stated that the referenced table row applies to ASME-equivalent Class 2 and 3 supports and is not applicable to Class MC supports, and that the response to RAI-3.5-6 will address the AMR results for Class MC supports.

Carbon Steel in a Submerged Environment – The staff requested that the applicant identify (1) the components included in this item, (2) where they are located, and (3) the submerged environment. The staff also requested the applicant to provide the technical basis for not including these component types in the One-Time Inspection Program to confirm the effectiveness of the Chemistry Control Program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 57 applies to carbon steel non-ASME Code equivalent supports inside the CWST. Aging of carbon steel supports submerged in the CWST (treated water environment) will be managed through monitoring CWST water chemistry by the Chemistry Control Program. Effectiveness of the CWST Chemistry Control Program will be confirmed by the One-Time Inspection Program of carbon steel mechanical components in a treated water (condensate water) environment as noted in LRA Table 3.4.2.2 (Condensate and Demineralized Water System).

The staff found the use of the Chemistry Control Program and confirmation by the One-Time Inspection Program acceptable to manage aging of submerged supports inside the condensate water storage tank, on the basis that the supports are treated as part of the tank in the applicant's AMR.

Lubrite in an Inside Air Environment - The staff requested that the applicant describe where the referenced items are used and provide the technical basis for concluding that no aging management of the lubrite plates used in BFN is required in an inside air environment.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 35 applies to the lubrite plates used for the core spray and RHR pump/equipment base supports. EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1," August 2003, states that lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. Lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The reactor building environment at the location of the core spray and RHR pump equipment base supports is not an aggressive or wetted environment.

The applicant also stated that a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4," and NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," concur that there are no lubrite plate aging effects that require aging management.

Based on the additional information provided by the applicant, the staff found the applicant's AMR results for lubrite plates to be acceptable. Prior staff evaluations of this issue have concluded that there are no aging effects requiring aging management.

Reinforced Concrete in a Buried Environment - This item applies to buried reinforced concrete equipment supports and foundations. The staff requested that the applicant explain how the Structures Monitoring Program is used to manage these buried (presumably inaccessible) components.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 41 applies to transformer pads/foundations in the transformer yard, 161kV switchyard and 500kV switchyard in a buried environment. The electrical equipment concrete foundations are exposed to both the outside air environment and the inaccessible buried environment. The outside air environment is addressed in LRA Table 3.5.2.26, row 44. Reduction in concrete anchor capacity will manifest itself at the anchor locations which are located in the outside air environment. The Structures Monitoring Program will manage reduction of concrete anchor capacity for those portions of the equipment foundations exposed to the outside air environment. Aging management for below grade inaccessible concrete will be based on inspection of the accessible concrete in the outside air environment.

Based on the additional information provided by the applicant, the staff found the applicant's AMR results for the buried portions of the concrete transformer pads/foundations to be acceptable. Periodic inspection of the accessible concrete by the Structures Monitoring Program will provide an indication of the condition of the buried concrete.

Stainless Steel in a Submerged Environment - The staff requested the applicant to identify (1) the ASME-equivalent supports and components included in this item, (2) where they are located, and (3) the submerged environment. The applicant was also requested to provide the BFN AMR for this item and discuss the technical basis for not crediting ASME Section XI, Subsection IWF as the AMP.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.26, row 11 applies to the stainless steel ASME-equivalent Class 2 supports for the safety-related valve (SRV) discharge lines that are in the submerged environment of the suppression pool water. The Chemistry Control Program and a one-time inspection will manage loss of material for stainless steel ASME-equivalent Class 2 supports exposed in a submerged treated (suppression pool) water environment. These lines are exempt from inspection per ASME Section XI.

Based on the additional information provided by the applicant, the staff accepts the applicant's AMR results for stainless steel ASME Code equivalent Class 2 supports for the SRV discharge lines that are in the submerged environment of the suppression pool water. The staff concurred that these supports are exempt from IWF inspection because they are not fluid filled. The credited AMPs are consistent with the GALL Report recommendations for Class 1 stainless steel small-bore piping. The staff found this appropriate, in lieu of IWF.

LRA Table 3.5.2.26 - In LRA Table 3.5.2.26, rows 5, 6, 10, 14, 15, 16, and 18, the applicant indicated that no aging management is required in containment atmosphere, inside air and outside air environments for stainless steel and non-ferrous aluminum ASME Code equivalent supports and components. Note 3 to LRA Table 3.5.2.26, which applies to all of the cited row numbers, states that there are no applicable aging effects for the material/environment combinations and that this is consistent with industry guidance. The applicant does not credit ASME Code AMP for license renewal.

It was the staff's understanding that the support components covered by the cited row numbers are required to be inspected under IWF during the current licensing term. Therefore, the staff requested that the applicant explain why this CLB commitment would not continue for the extended period of operation.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that these ASME-equivalent supports and components will continue to be inspected consistent with the commitments contained in the CLB for the ASME Code Section XI Subsection IWF Program requirements in effect during the extended period of operation. The applicant further stated that the specific reference to row numbers noted in the audit team's question all had material and environmental combinations that, upon performance of the AMR, determined that there were no aging effects that required managing for license renewal.

The staff noted inconsistencies between the applicant's AMR for the cited row numbers, all of which are not susceptible to general corrosion, and the applicant's AMR for carbon steel ASME Code equivalent supports and components, which are susceptible to general corrosion. For the cited row numbers, the applicant considers corrosion to be the only age-related mechanism leading to loss of mechanical function. The applicant's position is that the other GALL Report listed mechanisms leading to loss of mechanical function (distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) are not age-related. On this basis, the applicant has concluded that aging management for loss of mechanical function is not applicable to the cited row numbers. However, for carbon steel ASME Code equivalent supports and components, the applicant identified additional GALL Report listed mechanisms as leading to loss of mechanical function (see LRA Table 3.5.2.26, rows 2, 4, 12, and 13); and credits IWF as the AMP for license renewal.

The staff's review of LRA Table 3.5.2.26 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI as discussed below.

In RAI 7.2.5-2, dated March 8, 2005, the staff requested the applicant to: (1) submit a detailed description of all supports covered by LRA Table 3.5.2.26, rows 5, 6, 10, 14, 15, 16, and 18; and (2) for each support, provide the technical basis for concluding that every GALL Report listed mechanism (corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) leading to loss of mechanical function is not applicable. As an alternative, the applicant may credit IWF as an AMP for license renewal.

In its response, by letter dated April 5, 2005, the applicant provided its formal response, which states:

> For row numbers 5, 6, 15, and 16 of Table 3.5.2.26, the table will be revised to credit IWF as the aging management program.
>
> The supports for row number 10 are the typical pipe supports comprised of steel structural shapes, welded or bolted together and attached to the concrete structure/building with base plates or attached to other steel structural shapes of the building. The aging effect for GALL III.B1.2.1-a is “Loss of Material” and not “Loss of Mechanical Function” as noted in the question. The AMR is consistent with the reference to Note 3 of Table 3.5.2.26. Additionally, this is consistent with the proposed revision to GALL for Item number III.B1.2-5 (TP-5) for this material and environment combination. The AMR conclusion for the proposed GALL revision to GALL for Item number III.B1.2-5 (TP-5) is “no aging effects are applicable”; therefore, no AMP is required.
>
> The supports in-scope for row number 14 of Table 3.5.2.26 are integral welded lugs to the process pipe. The lug material is the same as the process pipe (aluminum). Aluminum external surfaces are not susceptible to corrosion unless their surfaces are wetted or exposed to an aggressive environment. Since periodic wetting or exposure to aggressive environments of component external surfaces in an inside air environment will not occur, loss of mechanical function due to corrosion is not considered plausible and the other aging mechanisms (distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) do not apply.
>
> The supports in-scope for row number 18 of Table 3.5.2.26 are integral welded lugs to the process pipe. The lug material is the same as the process pipe (stainless steel). The in-scope piping system is located in the Residual Heat Removal Service Water (RHRSW) Tunnels (LRA Section 2.4.3.5). Since the piping and supports are located within the RHRSW Tunnels and are exposed to an inside air environment and are not exposed to an outside air environment as noted in the AMR table, Row 18 can be deleted. Row number 10 (applicable GALL item - III.B1.2.1-a) is the applicable AMR line item for the material and environment combinations of these stainless steel supports in the RHRSW Tunnel.

The staff reviewed the applicant’s response and found it acceptable since the AMRs are consistent with the GALL Report. Therefore, the staff’s concern described in RAI 7.2.5-2 is resolved.

In RAI 3.5-12, dated December 10, 2004, the staff stated that non-ferrous aluminum conduit and supports that are exposed to outside air are listed in LRA Table 3.5.2.26 as components having no applicable AERM; thus, no AMP is designated to manage their aging. Depending on the severity of the outside air environment to which the components are consistently exposed, some aluminum conduit and supports may experience loss of material aging effect. Therefore, the staff requested that the applicant discuss its past plant-specific inspection results of these supports in order to provide an operating experience-based justification for the above AMR finding.

In its response, by letter dated January 31, 2005, the applicant stated:

> The following list identifies aluminum components in an outside air environment:
>
> - electrical and I&C penetrations
> - conduits and supports
> - non-ASME equivalent supports
>
> Aluminum alloys containing zinc are susceptible to corrosion in wetted aggressive environments. However, the outside air environment does not contain contaminants that would cause an aggressive environment. In addition, the aluminum conduit and conduit supports are also constructed of 6063-T42 alloy that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Since the potential for concentration of contaminates is not significant, and the specific aluminum grade used in an outside air environment is more resistant to corrosion, loss of function due to corrosion is not considered plausible.
>
> A review of BFN operating history, the structures monitoring baseline inspection, and the results for the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for the following aluminum components:
>
> - electrical and I&C penetrations,
> - conduits and supports
> - non-ASME equivalent supports

Based on the applicant's additional information provided above and operating experience that (1) the potential for concentration of contaminates at BFN site is not significant, and the specific aluminum grade used in an outside air environment is more resistant to corrosion, loss of function due to corrosion is not considered plausible, and (2) a review of operating history, the structures monitoring baseline inspection, and the results of the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for the aluminum components. The staff found the AMR results for its aluminum components adequate and acceptable. Therefore, the staff's concern described in RAI 3.5-12 is resolved.

In RAI 3.5-13, dated December 10, 2005, the staff stated that LRA Table 3.5.2.26 lists equipment supports and foundations made of non-ferrous lubrite that are exposed to inside air environment as components having no AERM; therefore, no AMP is designated for the components. NUREG-1801, Table III.B1.1.3-a identifies loss of mechanical function, corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, and elastomer hardening as potentially applicable aging effects for the lubrite components, and designates ASME Code Section XI, Subsection IWF Program as the AMP to manage the listed aging effects. Therefore, the staff requested the applicant to discuss past plant-specific inspection and maintenance results of these lubrite supports in order to provide an operating experience-based justification for the LRA assessment.

In its response, by letter dated January 31, 2005, the applicant stated:

> The Table 3.5.2.26 entry applies to the lubrite plates used for the Core Spray and RHR pump equipment support plates. EPRI report 1002950, “Aging Effects for Structures and Structural Components (Structural Tools) Revision 1,” states that lubrite material resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The Browns Ferry reactor building environment at the location of the Core Spray and RHR pump equipment support plates is not an aggressive or wetted environment.
>
> A search of Browns Ferry and industry operating experience did not identify any instances of Lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, “Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4” and NUREG-1769, “Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3,” concur that there are no aging effects for lubrite plate that require aging management.

Based on the applicant’s additional information provided above that (1) the reactor building environment at the location of the core spray and RHR pump equipment support plates is not an aggressive or wetted environment, (2) lubrite products are solid, permanent, completely self lubricating, and require no maintenance, (3) a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects, and (4) prior staff positions taken with respect to the aging management of lubrite plate under similar environmental conditions, as reported in NUREGs 1759 and 1769, the staff found the applicant’s response to RAI 3.5-13 acceptable. Therefore the staff’s concern described in RAI 3.5-13 is resolved.

Conclusion. On the basis of its review, the staff found that the applicant appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant 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).

Sections 3.5.2.3.27 and 3.5.2.3.28. The following AMRs were added as a result of SER Sections 2.4.3.9 and 2.4.7.7, respectively.

3.5.2.3.27 South Access Retaining Walls – Summary of Aging Management Evaluation – Table 3.5.2.27

The staff reviewed added LRA Table 3.5.2.27, which summarizes the results of AMR evaluations for the south access retaining walls component groups.

On the basis of its review of the information provided in added LRA Section 3.5.2.1.27 and Table 3.5.2.27, the staff determined that the applicant had adequately identified applicable aging effects, and the AMP credited for managing the aging effects, for the south access retaining walls components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the south access retaining walls components acceptable.

3.5.2.3.28 Isolation Valve Pit – Summary of Aging Management Evaluation – Table 3.5.2.28

The staff reviewed added LRA Table 3.5.2.28, which summarizes the results of AMR evaluations for the isolation valve pit component groups.

On the basis of its review of the information provided in added LRA Section 3.5.2.1.28 and Table 3.5.2.28, the staff determined that the applicant had adequately identified applicable aging effects, and the AMP credited for managing the aging effects, for the isolation valve pit components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the isolation valve pit components acceptable.

3.5.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging of the containments, structures, and component supports components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the containments, structures, and component supports, as required by 10 CFR 54.21(d).

3.6 <u>Aging Management of Electrical and Instrumentation and Controls</u>

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and I&C components and component groups.

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant provided AMR results for components. In LRA Table 3.6.1, "Summary of Aging Management Evaluations for Electrical and Instrumentation and Control Systems Evaluated in Chapter VI of NUREG-1801," 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 groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the electrical and instrumentation and control components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with 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 had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.1.

In the onsite audit, the staff also reviewed those selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.6.2.2, dated July 2001. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects were identified and evaluating whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.6.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the electrical and I&C components.

Table 3.6-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.6 that are addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls 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 environmental qualification (EQ) requirements [Item Number 3.6.1.1 (F.4)]	Degradation due to various aging mechanisms	Environmental Qualification of Electrical Components Program	TLAA	This TLAA is evaluated in Section 4.4, Environmental Qualification
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 (IR); electrical failure caused by thermal/ thermoxidative degradation of organics; radiolysis and photolysis [ultra violet (UV) sensitive materials only] of organics; radiation-induced oxidation; moisture intrusion	Aging Management Program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging Management Program for Electrical Cables Used in Instrumentation Circuits not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Electrical Cables Used in Instrumentation Circuits not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.6.2.1)
Inaccessible medium-votlage (2kV to 15kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Formation of water trees; localized damage leading to electrical failure (breakdown of insulation) caused by moisture intrusion and water trees	Aging Management Program for Inaccessible Medium voltage Cables not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Inaccessible Medium voltage Cables not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.6.2.1, involves the staff's review of the AMR results in 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 SER Section 3.6.2.2, involves the staff's review of the AMR results for components in the electrical and I&C systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, involves the staff's review of the AMR results in the electrical and I&C components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.1, 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:

- Accessible Non-EQ Cables and Connections Inspection Program
- Bus Inspection Program
- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

- EQ Program
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

Staff Evaluation. In LRA Table 3.6.2.1, 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.

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 were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated 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 indicated 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 the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated 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 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 had the same material, environment, aging effect, and AMP as the component that was 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 was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated 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 verified whether the AMR line item of the different component is applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated 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 bases documents, which are available at the applicant's engineering office. On the basis of its audit and review, the staff found that the AMR results that the applicant claims to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff found that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

Conclusion. The staff evaluated 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 concluded that the AMR results that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the electrical components. The applicant provided information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ requirements
- QA for aging management of NSR components

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 audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification Requirements

EQ is a TLAA requiring further evaluation. TLAAs are evaluated in SER Section 4.

3.6.2.2.2 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 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 claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that: (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had 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).

3.6.2.3 *AMR Results That Are Not Consistent with or Not Addressed in the GALL Report*

Summary of Technical Information in the Application. In LRA Table 3.6.1, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Table 3.6.1, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report and provided information concerning how the aging effect will be managed.

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 had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

The applicant's AMR results that are not consistent with the GALL Report, or not addressed in the GALL Report, were not reviewed during the onsite audit.

3.6.2.3.1 Aging Management Evaluations - Fuse Holder

Fuse holders (including fuse clips and fuse blocks) are included consistent with Interim Staff Guidance (ISG)-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," dated March 10, 2003. ISG-05 added NRC guidance for the identification and treatment of electrical fuse holders for license renewal, which stipulates that fuse holders will be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections. The guidance also says that an appropriate AMP should be adopted to manage the effects of aging where necessary.

Consistent with that staff guidance, the applicant identified oxidation, corrosion of connecting surfaces, moisture or chemical contamination, loosening of connection/thermal cycling, wear, fatigue, loosening of connection/vibration, deformation, and loosening of connection/mechanical stresses as the aging mechanism/effects for the fuse holders.

In the LRA, the applicant stated that plant installation and maintenance practices provide appropriate protection for fuse holders from moisture intrusion, such as in enclosures, since fuse holders are protected by their location within a controlled environment. Therefore, oxidation/corrosion of connecting surfaces due to exposure to moisture or chemical contamination is not an AERM. The applicant also stated that fuse holders in use are designed to withstand the ratings of the fuses they house. Thus, fuse holders are protected from thermal cycling by their design, which prevents the aging effect of fuse clip/finger loosening, and requires no AMP. Fuse holders are mounted in their own support structure separated from sources of vibration; therefore, vibration is not a concern for fuse holders, and an AMP is not required. The fuses are not routinely pulled and reinserted potentially causing fatigue of the fuse holder clips.

Based on the above, the applicant concluded that fuse holders at BFN will maintain their intended function through the period of extended operation with no AMP required.

In RAI 3.6-5, dated November 4, 2004, the staff asked the applicant to justify how a controlled environment could provide protection for fuse holders, preventing aging from the effects of temperature, humidity, radiation, and fatigue. The staff also asked the applicant whether the actual condition of the fuse holders was evaluated to assess the extent of use and whether any visual inspection was performed on the fuse holders; if so, the applicant was requested to provide the findings or explain why an assessment of their current condition was not necessary.

In its response, by letter dated December 9, 2004, the applicant stated:

> A controlled environment, as it pertains to fuse holders, is one where the fuse holder is installed in an enclosure that protects the fuse holder from exposure to moisture and chemical contamination. Enclosures at BFN are designed and selected for the environment in which they are installed. National Electrical Manufacturers Association (NEMA) Standards imposed during the design process ensures the enclosure is suited for the environment in which it is installed. In addition, conduits entering the enclosure were sealed, along with unused knockouts. Enclosure tops and non-welded seams are sealed, along with enclosure and component mounting screws/bolts. Door gaskets supplied with NEMA enclosures are acceptable, or the enclosure door is sealed utilizing engineering approved maintenance instructions.
>
> The aging mechanisms of temperature and radiation are not applicable to the fuse clip portion of fuse holders, but are applicable to the polymeric base material. Polymeric materials of fuse holders utilized at BFN were evaluated as insulated connections and are acceptable for the extended period of operation in the environments in which they are presently installed. None of the polymeric material's 60-year bounding temperature or radiation values were exceeded in any plant space where fuse holders are installed at BFN.

By email dated December 15, 2004, the staff requested additional information on the subject. In its response, by letter dated January 18, 2005, the applicant stated that polymeric materials of fuse holders are included in the Accessible Non-EQ Cable and Connections Inspection Program.

On the issue of fatigue, mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. Fuse holders in use are designed to withstand the ratings of the fuses they house and are selected to ensure they are operated below their rated load. Thus by design, fuse holder clips and connections are protected from fatigue failure due to thermal cycling.

Industry operating experience as documented in NUREG-1760 "Aging Assessment of Safety-Related Fuses used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identified that fuse failures due to thermal cycling are attributed to the fuse element, not fuse holder clips. NUREG-1760 documents no instances of fuse holder clip fatigue failures attributed to thermal cycling. A visual inspection performed on a sample located in outdoor weather conditions did not reveal visual signs of corrosion or degradation.

On the basis of its review, the staff found that the applicant had addressed the staff's concern adequately; therefore, the staff's concern described in RAI 3.6-5 is resolved. The staff also found that no AMP is required to manage the aging effects of fuse holders.

3.6.2.3.2 Aging Management Evaluations - Insulated Cables and Connections

In LRA Section 3.6.2.3.2, the applicant identified the electrical failures due to moisture intrusion, which was addressed in SAND 96-0344, "Aging Management Guidelines for Commercial Nuclear Power Plants - Electrical Cable and Terminations," and TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables."

In evaluating these aging effects, the applicant, in the LRA, said that plant installation and maintenance practices provide appropriate protection for connectors from moisture (such as connectors in enclosures or covered with Raychem tubing/splices or tape). Therefore, aging effects related to moisture intrusion for low-voltage cables and connectors do not require aging management for the period of extended operation. However, this aging effect/mechanism is prevalent in medium voltage cables (i.e., water treeing) which is managed by the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff agreed that the applicant had correctly concluded that no separate AMP is required to manage aging effects related to moisture intrusion for low-voltage cables and connectors. The staff found that the GALL Report addressed the aging effect/mechanism in inaccessible medium voltage cables, which will be adequately managed by the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

3.6.2.3.3 Aging Management Evaluations - High-Voltage Insulators

High-voltage insulators typically used on transmission towers are insulating materials in a form designed to (a) support the conductor physically and (b) separate the conductor electrically from another conductor or object. Materials used for the high-voltage insulators are porcelain and metal.

In LRA Section 3.6.2.3.3, the applicant identified surface contamination, cracking, and loss of material due to mechanical wear as the aging effects/mechanism for high-voltage insulators.

In managing these aging effects, the applicant evaluated these effects as follows:

Surface Contamination - the buildup of surface contamination is gradual and in most areas such contamination is washed away by rain. Contamination buildup on insulators is not a problem due to rainfall periodically washing the insulators.

Cracking - Cracking and breaking of porcelain insulators is typically caused by physical damage, which is not an aging effect and is not subject to an AMR. A review of plant-specific operating experience revealed no instances of insulator cracking or failure related to cement growth at the switchyard. Cracks have also been known to occur with insulators when the cement binds the parts together enough to crack the porcelain. This phenomenon is known as cement growth, and is caused by improper manufacturing process or materials that makes the cement more susceptible to moisture penetration. Therefore, cracking of high-voltage insulators due to cement growth is not an AERM for the period of extended operation

Mechanical Wear - Mechanical wear is an aging mechanism for strain and suspension insulators in that they are subject to movement. Although this mechanism is possible, industry experience has shown that transmission conductors do not normally swing, and when they do swing, as a result of a substantial wind, they do not continue to swing for very long once the wind subsides. In the applicant's evaluation, wear has not been identified during maintenance activities on BFN insulators.

The staff concluded that the applicant had adequately addressed the aging management for high-voltage insulators and agreed that no AMP was required for high-voltage insulators.

3.6.2.3.4 Aging Management Evaluations - Transmission Conductors and Connections

Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations, and transmission lines to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers, to a passive switchyard bus. Typical transmission conductor materials are aluminum conductor steel reinforced (ACSR).

In LRA Section 3.6.2.3.4, the applicant stated that the portions of transmission conductor within the scope of license renewal for BFN are all aluminum conductors. All aluminum conductors, unlike ACSR, are not as susceptible to environmental influences, such as sulphur dioxide concentration in air. When aluminum corrodes, it forms a protective oxide layer which protects the underlying material from further corrosion. When the steel core of ACSR corrodes due to losing its galvanized coating, it will continually corrode causing a decrease in ultimate strength. The two types of aluminum conductors used at BFN are Orchid, 636 mcm, and Coreopsis, 1590 mcm, which have an ASTM rated strength of 11,000 lbs and 27,000 lbs respectively. The maximum load permitted by TVA design is 3000 lbs for Orchid and 6000 lbs for Coreopsis, which results in a margin of 73 percent and 77 percent of the rated strength. Using the same percent decrease in ultimate strength of 33 percent from the Ontario Hydroelectric test, the aluminum conductors at BFN would undergo a loss of rated strength of 3663 lbs for Orchid and 8910 lbs for Coreopsis. The new rated strength/margin of rated strength would be 7437 lbs/40 percent and 18090 lbs/44 percent for Orchid and Coreopsis, respectively. The ultimate strengths are well above TVA's maximum design load and the National Electrical Safety Code margin of ultimate load, 6660 lbs for Orchid and 16200 lbs for Coreopsis, for the original conductors. Although corrosion of aluminum is minimal, a decrease in ultimate strength due to corrosion similar to that of the ACSR conductor tested by Ontario Hydroelectric shows that the aluminum conductors at BFN will continue to perform their intended functions for the period of extended operation. Further, the applicant stated that transmission and power supply personnel perform normal maintenance activities on all portions of the switchyard, including transmission conductors. These maintenance activities have not revealed any aging effects/mechanisms associated with transmission lines to date. In conclusion, there are no applicable aging effects that could cause loss of the intended function of the transmission conductors. Therefore, loss of conductor strength due to corrosion of transmission conductors is not an AERM for the period of extended operation.

Industry experience has shown that transmission conductors do not normally swing, and that when they do swing in substantial wind, they do not continue to swing for very long once the wind subsides. Therefore, loss of material (wear) and fatigue due to wind loading vibration or sway of transmission conductors are not applicable AERMs for the period of extended operation.

The applicant concluded that no AMP is required.

In RAI 3.6-8, dated November 4, 2004, the staff raised a concern regarding the torque relaxation for bolted connections for transmission conductor and switchyard bus connections.

In its response, by letter dated December 9, 2004, the applicant stated that bolted switchyard bus and transmission conductor connections at BFN utilize Belleville washers, which have torque applied until the Belleville washer is flat, not to exceed limits specified by bolt size. In accordance with industry guidance EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," (Section 7.2.2), increased temperature difference in electrical bolted joints is due to high short circuit ratings or increased current duration. The temperature of an electrical bolted joint will rise and the stress will increase with increasing current duration. If this temperature increase is not taken into consideration, loose, failure-prone joints will result. Belleville washers selected to be flat or almost flat at the installation torque will be used to accommodate the temperature increase. At BFN, connections are routinely surveyed using infrared scan for hot spots, which are indicative of a degraded connection. If a hot spot at a connection is discovered, corrective actions are taken to repair the connection.

In a supplemental letter, dated January 18, 2005, in response to a staff follow-up question, the applicant stated that the infrared scans are performed using Transmission Power Supply Routine Test Schedule. This schedule requires that 500 kV and 161 kV switchyard connections be surveyed after a modification and routinely surveyed every six months. A review of plant-specific operating experience did not reveal any age-related issues associated with bolted switchyard bus or transmission conductor connections; therefore, torque relaxation of bolted switchyard bus and transmission conductor connections is not a concern for BFN.

On the basis of its review, the staff's concern described in RAI 3.6-8 is resolved.

The staff concluded that although corrosion of aluminum is minimal, a decrease in ultimate strength due to corrosion similar to that of the ACSR conductor tested by Ontario Hydroelectric shows that the all aluminum conductors at BFN will continue to perform their intended functions for the period of extended operation. Also, based on the response to the staff concern regarding the torque relaxation for bolted connections, the concern raised in RAI 3.6-8 was resolved. The staff agreed with the applicant's evaluations and concluded that the applicant had adequately addressed the aging management for transmission conductors and connections. The staff also agreed that no AMP was required.

3.6.2.3.5 Aging Management Evaluations - Switchyard Bus

Switchyard buses electrically connect specified sections of an electrical circuit to deliver voltage or current to various equipment and components throughout the plant. The switchyard bus is used in switchyards to connect two or more elements of an electrical power circuit such as active disconnect switches and passive transmission conductors.

In LRA Section 3.6.2.3.5, the applicant identified cracking due to vibration and change in material properties leading to increased resistance and heating as a result of connection surface oxidation as potential aging effects for the high-voltage switchyard bus. In managing the aging effects, the applicant stated that switchyard buses connected to circuit breakers via flexible aluminum conductors, those supported by insulators and by structural supports such as concrete footing or steel structures, do not vibrate. Also, the design process for switchyard bus was engineered to dampen any vibrations that might be induced into the buses. Therefore, cracking due to vibration is not an applicable aging effect for switchyard buses, and an AMP is not required.

The applicant also identified aging effects due to change in material properties leading to increased resistance and heating as a result of connection surface oxidation in aluminum buses. Solid and flexible connectors and ground straps are highly conductive but do not make a good contact surface since pure aluminum exposed to air forms aluminum oxide on the surface, which is nonconductive. To prevent the formation of aluminum oxide on bolted connection surfaces, the connections have a silver plating and are covered with grease to prevent air from contacting the connection surface. The grease is a consumable item that is applied to the connection surface each time a bolted connection is made, thereby precluding oxidation of the connection surface and maintaining good conductivity at the bus connections. Therefore, change in material properties leading to increased resistance and heating as a result of connection surface oxidation of aluminum buses is not an AERM for the period of extended operation.

In RAI 3.6-7, dated November 4, 2004, the staff requested the applicant to provide a discussion of the grease replacement program including the frequency.

In its response, by letter December 9, 2004, the applicant stated that grease is a consumable item that is applied each time a bolted connection is made, and that it precludes oxidation of the connection surface and maintains good conductivity at the bus connections. Connections are routinely surveyed using infrared scan for hot spots, which are indicative of a degraded connection. In its response, the applicant stated that if a hot spot at a connection is discovered, corrective actions are taken to repair the connection. In a supplemental response, dated January 18, 2005, to a staff follow up-question, the applicant stated that the infrared scans are performed using the Transmission Power Supply Routine Test Schedule. The Transmission Power Supply Routine Test Schedule states that 500 kV and 161 kV switchyard connections are surveyed after a modification and routinely surveyed every six months. On the basis of its review, the staff found that its concern described in RAI 3.6-7 is resolved.

The staff concurred with the applicant's evaluation and concluded that no AMP is required to manage these components. The staff also found that the applicant had adequately addressed why these aging effects are not applicable aging effects at BFN. The staff agrees that there is reasonable assurance that the switchyard bus will perform its intended function for the period of extended operation.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant had 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).

3.6.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging of the electrical and I&C components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of the electrical and I&C components, as required by 10 CFR 54.21(d).

3.7 Aging Management Review of Unit 1 Systems in Layup for Extended Outage

3.7.1 General Technical Concerns

LRA Section 3.0.1 contains a summary of the evaluation of systems and components subjected to the Unit 1 layup and preservation program. Staff initially reviewed LRA Section 3.0.1 and determined that additional information was required. By letter dated February 19, 2004, the applicant submitted a supplement to the LRA dedicated to the Unit 1 systems in layup during the extended outage. The staff then issued a series of RAIs to obtain additional information on the aging management of components subjected to layup conditions during the extended outage. During the staff review, it was determined that license renewal and plant restart were to be decoupled and, as a result, plant changes to support restart were to be primarily evaluated independently as part of the restart effort. The staff focused its layup and preservation program review on consistency with industry guidance, operating experience including restart inspections, potential latent aging effects, and the adequacy of one-time inspections to manage systems not in service during the extended outage.

In addition to the layup and preservation program, a combination of factors related to operating experience contribute to the way aging effects are managed for systems that were not in service during the extended outage. Those factors are addressed below.

- Length of Extended Outage - The Unit 1 extended outage lasted for approximately twenty years. The length of this extended outage was significantly longer than the extended outage for either Unit 2 or Unit 3 and is unique in the industry. The extended outage limited the amount of Unit 1 operating experience available for review and created abnormal internal environments that contributed to aging.
- Limited Operating Experience - The length of the Unit 1 extended outage limited the amount of operating experience and data available for use in aging management reviews. Unless there is sufficient data available, one-time inspections may not be appropriate to manage systems that were not in service during the extended outage. In response to Item 5.B, discussed below, the applicant provided additional information concerning Units 2 and 3 restart programs and layup operating experience that is applicable to Unit 1.
- Replacement of Components - LRA Appendix F identified that large portions of systems and components were replaced. The basis for material replacement was either the result of excessive degradation caused by ineffective layup practices or potential susceptibility to known degradation mechanisms. The primary concern for aging management is associated with components that were not replaced.
- Suspension of Maintenance Rule - By letter dated August 9, 1999, the staff issued a temporary partial exemption from 10 CFR 50.65 for Unit 1. This partial exemption provided relief from the Maintenance Rule for systems that were not in service to support Units 2 and 3.

Evaluation Findings

SER Section 3.7 contains the staff evaluation of Unit 1 systems subject to layup conditions during the extended outage. SER Section 3.7 includes an evaluation of general technical concerns and system-specific concerns relevant to systems and components subjected to layup conditions. This evaluation determined that, due to a number of factors including (1) service conditions resulting from potentially ineffective layup practices, (2) the length of the extended outage period, (3) limited operating experience, (4) replacement of degraded material due to ineffective layup practices, and (5) suspension of maintenance activities for systems subject to layup, periodic inspections would be more appropriate than one-time inspections to manage aging effects in systems that were subject to layup conditions, where latent aging effects may have existed. The applicant agreed to a periodic inspection program to manage systems that were not replaced and were not in service during the extended outage. Details of the program were not available at the time the SER with open items was prepared. The ACRS interim report dated October 19, 2005, agreed with staff that additional information was required to support the staff review of the wet layup sections and periodic inspection program versus one-time inspection program.

Unresolved Items

By letter dated October 31, 2005, the staff summarized the following unresolved items related to the layup and preservation program and requested the applicant to provide additional information to address unresolved items raised in the committee's interim report:

- Providing suitable input for the wet layup sections for the SER so that the staff can write a cohesive safety evaluation on the applicability of Units 2 and 3 experience to Unit 1.
- Clarification of One-Time Inspection Program versus Unit 1 Periodic Inspection Program and One-Time Inspection Program consistency with the GALL Report.

The applicant, by letter dated November 16, 2005, submitted additional information, discussed below, to close out the unresolved items related to systems subject to the layup and preservation program.

Restart Programs and Unit 2 and 3 Layup Operating Experience Applicable to Unit 1

BFN Unit 1 was licensed and began initial operation in 1973. Unit 2 began operation in 1974. Units 1 and 2 operated until March 22, 1975, at which time both units were shut down due to a fire in the Unit 1 reactor building. Units 1 and 2 resumed operation in 1976 and Unit 3 began initial operation in 1977. All three units were operated until March 1985, at which time the applicant voluntarily shut them down to address regulatory and management issues.

Following successful resolution of the management issues and the Unit 2 and common regulatory issues, Unit 2 was restarted on May 23, 1991. Unit 3 remained in a layup/recovery mode for approximately 10 years and, following resolution of the Unit 3 regulatory issues, it was restarted on November 19, 1995. Both units have operated with high capacity factors into the present time. In the early 1990s, the applicant decided to defer restart of BFN Unit 1.

On May 16, 2002, the applicant announced the Unit 1 restart project. As part of the Unit 1 restart project, the applicant is performing the same restart programs and implementing the same modifications that were previously completed on Units 2 and 3. At restart, Unit 1 will be operationally the same as Units 2 and 3. The current planned Unit 1 restart date is May 2007.

The Unit 1 systems that perform a required function in the defueled condition, or that directly support Unit 2 or Unit 3 operation, have been continuously operated and maintained under applicable technical specifications and plant programs since shutdown in 1985. Examples of these systems are:

- fuel pool cooling system
- portions of the control rod drive (CRD) system
- portions of the raw cooling water (RCW) system
- portions of the reactor building closed cooling water (RBCCW) system
- portions of the residual heat removal (RHR) system
- portions of the residual heat removal service water (RHRSW) system
- portions of the emergency equipment cooling water (EECW) system
- portions of the control air system

The applicant maintained the Unit 1 systems in a physical condition during shutdown similar to that of Units 2 and 3 during their shutdown periods. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as those found in the operating units. These systems have experienced the same aging mechanisms and rates experienced by similar Units 2 and 3 systems for shutdown conditions. The Units 1, 2, and 3 reactor buildings are one continuous structure, and the external operating environments of the systems are the same. Even though Unit 1 was in an extended outage, the overall environmental conditions affecting external surfaces in Unit 1 was maintained consistent with those of Units 2 and 3. Unit 1 had the normal ventilation systems in service and equipment was maintained to prevent system leakage so that the equipment was not subjected to aggressive external conditions.

Unit 3 was shut down for approximately 10 years: from 1985 to 1995. The aging effects on Unit 3 were monitored and addressed prior to startup in 1995. Since 1995, Unit 3 has operated with a high capacity factor and was uprated 5 percent reactor thermal power in 1998. During this 10-year period of operation, no additional aging effects have been identified attributable to the 10 years of shutdown and layup. Since Unit 1 was laid up and maintained using the same method as Unit 3, the aging effects during the layup and subsequent operation of Unit 3 would be expected to apply equally to Unit 1. Unit 2 and 3 operations, including power up-rate, have not resulted in any unexpected aging mechanisms or rates. Unit 1 operation, following the shutdown and associated replacements/refurbishments, is expected to exhibit the same aging mechanisms and rates as Units 2 and 3.

Other Unit 1 systems have been in a layup condition, and prior layup experience from Unit 3 has been applied to Unit 1 license renewal. Some piping systems (or portions of piping systems) were placed in a "wet layup" under the applicant's Unit 1 layup procedure, including:

- reactor vessel
- reactor water recirculation system
- reactor water cleanup system

- portions of the RHR system
- portions of the core spray (CS) system
- portions of the feedwater (FW) system

The water chemistry within these Unit 1 piping systems was monitored for compliance with the water quality requirements. Thus, it would not be expected that a different aging mechanism or rate would exist in wet layup compared to what would have occurred if the system were in normal operation. The full scope of BWRVIP inspections have been performed on the Unit 1 reactor vessel as part of the restart project. No adverse effects from the layup period were found and repairs/replacements not related to layup will be performed as required. The reactor water recirculation system and reactor water cleanup system piping, both large bore and small bore, have been replaced. The RHR and CS piping that was in wet layup has also been replaced. The piping was replaced with the same materials that were used in Units 2 and 3. Ultrasonic inspections of the feedwater piping have confirmed that the piping does not exhibit adverse effects from the wet layup period.

Some Unit 1 piping systems (or portions of piping systems) were drained and placed in dry layup, including:

- reactor core isolation cooling (RCIC) system
- high pressure coolant injection (HPCI) system
- main steam (MS) system
- portions of the RHR system
- portions of the CS system
- portions of the FW system

The exterior of the system/component was maintained at nominal reactor or turbine buildings ambient conditions which would have been the same in Units 1, 2, and 3. Thus, the dry layup systems would have experienced aging at a rate less than or equal to that of the corresponding Unit 2 or Unit 3 system.

Some Unit 1 systems were simply drained with no controlled environment. As a result, portions of two Unit 1 systems experienced accelerated aging. The accelerated aging of these systems was previously identified as part of the operating experience from the Unit 3 outage between 1985 and 1995. These were portions of the Unit 1 RHRSW piping inside the reactor building and some small bore raw cooling water piping. As explained below, this prior Unit 2 or Unit 3 operating experience was incorporated into Unit 1 aging management activities.

The RHRSW piping normally contains raw water from the river. Some of the Unit 1 RHRSW piping inside the reactor building was drained in 1985, but moisture-laden air remained in the system. The piping enters/exits from the RHRSW tunnels. Inside the tunnels, the piping is exposed (i.e., not buried) for approximately 100 feet after which it becomes buried pipe out to the intake pumping station. The buried piping could not be drained since it is below grade. Water from the buried section of piping vaporized and entered the drained, above-grade piping in both the tunnels and the reactor building. Inside the RHRSW tunnels, which are approximately 20 feet under an earthen berm, the ambient temperature was cool and no adverse reactions occurred inside the RHRSW piping. However, the RHRSW piping inside the reactor building experienced normal ambient conditions (i.e., 65°F to 90°F). In this warm, moisture-laden environment, severe corrosion occurred necessitating complete replacement of the pipe. As shown by ultrasonic measurements of pipe wall thickness and visual observations of pipe interiors, this aging effect was not experienced by buried pipe or above grade pipe that was full of water. This aging effect was restricted to the RHRSW system because it is the only system that was drained but allowed to contain moisture-laden air. This aging was first identified on Unit 3 during the Unit 3 recovery and necessitated the replacement of all of the RHRSW piping inside the Unit 3 reactor building. Based on this lesson learned, the required pipe replacement was performed for the Unit 1 A and C loops of RHRSW piping, which had been in a similar layup fashion to the Unit 3 piping.

The small bore RCW piping was drained; however, due to valve leakage, some water was reintroduced into the system. The combination of water and trapped air set up virtually the same corrosion effects described above for the RHRSW piping. The Unit 1 recovery project has visually and ultrasonically inspected the small bore raw water piping and is replacing approximately 3000 feet of degraded piping.

The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components for restart. TVA either replaced the piping and components or performed appropriate visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced, as discussed in the applicant's letter to the staff, dated May 18, 2005. For systems, piping, and components that were replaced, no layup effects are present. The Unit 1 structures, systems, and components within the scope of license renewal will be subject to the existing BFN aging management programs. As a compensatory measure for systems and components not being replaced, the applicant will perform targeted periodic inspections for the Unit 1 systems that were not replaced as part of the Unit 1 restart project. These inspections will provide heightened assurance that existing AMPs address relevant aging mechanisms and effects for Unit 1.

To ensure there are no latent aging effects as a result of the layup program, BFN will implement a targeted periodic inspection program for Unit 1 system piping that was not replaced as part of the Unit 1 restart project. The restart inspection will provide baseline measurements for targeted inspections to be performed after the unit is returned to operation to verify aging management program effectiveness and to verify the absence of additional latent aging effects. The selected sample will be examined by the same or equivalent methodology as used during Unit 1 restart. Systems (or portions of systems) where periodic inspections will be performed include MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD.

After restart in 2007, Unit 1 would have six years of operation remaining in the current license period, prior to the period of extended operation. The first periodic inspection will be performed during the current license period. An inspection also will be performed during the period of extended operation. Subsequent inspection frequency will be determined based on the inspection results. Inspections will continue until the trend of results provides a basis to discontinue the inspection. There is reasonable confidence that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects after the systems are returned to service.

As part of the AMR in support of the LRA, the applicant recognized that due to the layup period the Unit 1 operating experience may not be the same as the operating experience for Units 2 and 3. Thus, as a further compensatory action, the applicant performed evaluations to identify new aging effects that could be applicable to Unit 1 as a result of the layup environment. The material groupings and aging effects were established using the same approach utilized in the rest of the LRA. A detailed evaluation was performed for 19 Unit 1 systems. It was concluded that there were no new AERMs during the renewal term. A summary of these evaluations is provided in LRA Section 3.0.1. The applicant provided additional details of this evaluation in its letter to the staff dated February 19, 2004.

As part of its review of the applicant's LRA, the staff, by letter dated August 23, 2004, identified areas where additional information was needed to complete its review. The specific staff questions were from LRA Sections 3.1, 3.2, 3.3, and 3.4 and were related to aging of mechanical systems during the extended Unit 1 outage. Listed below are the specific staff requests for additional information, responses to a number of staff follow-ups, and the LRA. There were no additional aging effects because of the extended outage of Unit 1 and, consequently, the applicant claimed that there was no need for any additional aging management. However, in its letter dated August 23, 2004, the staff said that since the aging of mechanical systems is highly dependent on the environment maintained during the extended outage, the staff needed additional information to determine whether:

- Additional or more severe aging occurred during the extended outage.
- Additional aging has been properly identified, evaluated, and managed.
- The proposed aging management can distinguish the aging during the extended outage from the aging during future operation.

By the initial set of RAIs dated August 23, 2004, the staff issued general and system-specific RAIs on the aging of mechanical systems during the extended outage of Unit 1. The applicant responded to the initial RAIs by letter dated October 8, 2004. The staff reviewed the applicant's RAI responses and, by letter dated December 16, 2004, requested additional information in a set of follow-up RAIs. The applicant responded to these RAIs by letters dated January 20, and January 31, 2005. System-specific RAIs are identified by a system-specific LRA prescript and a subscript "LP" to designate a layup RAI. Finally, the applicant resolved all the staff issues regarding the Unit 1 layup by its responses dated May 18, and May 27, 2005. RAIs (3.0-1 LP through 3.0-11 LP) are applicable to all systems. Given below are the safety evaluations of technical areas in which the staff had specific concerns relative to the Unit 1 system in the extended layup and its rationale for acceptance.

3.7.1.1 Wet Layup Program Chemistry Control

In the wet layup for Unit 1, the applicant characterized chemistry for the wet layup water as flowing, air-saturated, and demineralized. Since in the BFN plant only the systems carrying the reactor cooling water are included in the wet layup program, the chemistry of the demineralized water has the same chemistry as the cold shutdown reactor cooling water during normal plant outages.

The initial set of general RAIs that are referenced in the discussion that follows constitutes the staff request dated August 23, 2004. The applicant's responses are in its letter dated October 8, 2004.

In its response to RAI 3.0-1 LP by its letter dated October 8, 2004, the applicant stated that the other plant systems with different plant chemistries were not included in the wet layup program because during the Unit 1 outage they were maintained at the operating conditions, including water chemistries, found in Units 2 and 3 during their normal operations. The cold shutdown chemistry is specified in the BFN CI-13.1 chemistry program. In the response to the staff's question the applicant stated that the chemistry control limits implemented during wet layup are 1.5 µS/cm for water conductivity, and 15 ppb for the concentration of chloride and sulfate. These values are the same as the chemistry control limits utilized in Units 2 and 3 operating in the cold shutdown mode for refueling and maintenance outages. They are more restrictive than those in the EPRI Water Chemistry Guidelines specified in BWRVIP-79 and, therefore, introduce conservatism to the values of the CI-13.1 chemistry program used to specify water chemistry during the wet layup.

Since water conductivity and concentration of chlorides and sulfates are the main parameters characterizing water chemistry, as long as they don't differ, the wet layup and cold shutdown chemistries are comparable. The staff concurred, therefore, with the applicant that the effect of chemistry on the components in wet layup and cold shutdown will be similar, and the exposure of the components to the wet layup chemistries will be similar to the effect of the exposure to reactor water during the cold shutdown mode of operation.

3.7.1.2 Replaced Components

LRA Appendix F indicates that significant sections of piping and components have been or will be replaced prior to Unit 1 restart. It was not clear to the staff whether LRA Appendix F included all piping that had been or would be replaced prior to restart. The applicant's responses to staff RAI for LRA Section B.2.1.4, developed during the license renewal audit inspection during the weeks of June 21 and July 26, 2004, state that repaired or replaced components will receive a preservice examination in accordance with the requirements of IWB, IWC, or IWD of the component being repaired or replaced, and prior to returning the system to service. In this response, the applicant also stated that a re-baseline inspection will be performed on the remaining Class 1, 2, and 3 components that have not been repaired or replaced.

In RAI 3.0-9 LP (refurbished vs left in place), dated December 16, 2004, the applicant was requested to provide information to identify the basis, such as inspections or suspected degradation, to determine which components need to be replaced and those that do not. Also, the applicant was requested to clarify whether Appendix F includes all piping and components that will be replaced prior to startup and to identify in a simplified boundary diagram those specific sections of piping and components that have recently been or will be replaced and those that have not been replaced. Further, the applicant was requested to clarify appropriate layup or cleanliness programs (Refer to RAI 3.0-11 LP) and inspections that are in use and planned for these components. For those systems or portions of systems and components that have not been recently replaced and were subject to the extended layup, the applicant was requested to provide the information requested in RAI 3.0-10 LP (inspection information, concerning inspections).

In its response, by letter dated January 31, 2005, the applicant stated that the overall management philosophy for the Unit 1 restart was to return the plant to operation in a condition that would support long-term safe and reliable operation of the unit, including the

20-year period following license renewal. The applicant further stated that, with this management philosophy as a basis, it had applied lessons learned from the Units 2 and 3 restart programs and operating experience from all three units in its decision to replace large portions of key piping systems. The RAI 3.0-9 LP response also states that the Unit 1 restart project did not credit the layup program as the sole means of establishing the acceptability of the associated piping and components. Rather, the applicant either replaced the piping and components or performed appropriate inspections to establish the physical condition of systems and components not being replaced.

The applicant's response to RAI 3.0-9 LP also states that LRA Appendix F did not include all piping and components that will be replaced prior to startup.

In summary, the RAI response concluded that the application of the targeted sampling inspections and the number of inspections performed has established a high level of confidence that those systems with any question about their integrity have been identified, inspected, and properly addressed relative to the replacement or non-replacement of the piping system and/or its components. The combination of piping replacements identified through previously identified design issues, operating experience, and other inspections identified approximately 16,000 feet of large bore piping and 26,000 feet of small bore piping to be replaced. The applicant further stated that the results of the reviews of operating experience, design issues, and inspections is provided in Table 1 of the RAI response. The systems listed are those in which significant piping or components were identified for replacement or refurbishment. In its response, the applicant presented in Table 2 of the submittal dated January 31, 2005, the details and extent of the RPV vessel inspection project (VIP) inspections and ASME Section XI re-baseline inspections that will be conducted on Unit 1 piping systems prior to operation. Finally the applicant stated that the re-baseline effort is equivalent to performing a complete 10-year interval's quantity of examinations during the Unit 1 restart effort.

The staff reviewed the applicant's response to RAI 3.0-9 LP and found the response to be reasonable and acceptable to clarify the general scope of replaced and refurbished components including the basis for replacing certain components and not others. The applicant's response and the staff's evaluation of the response is included in the applicable section for each system.

The applicant's response to RAI 3.0-9 LP states that LRA Appendix F did not include all piping and components that will be replaced prior to startup. As a result, LRA Appendix F cannot be used as a means to distinguish between sections of piping systems and components that have been replaced and those that have not been replaced. Although the response to RAI 3.0-9 LP identifies examples of piping systems and components that have been replaced, the staff is unable to identify specific components that have not been replaced that were subject to layup conditions. Further, the scope and results of sample inspections, including the sampling basis, have not been identified. To identify the scope and condition of components subject to Section XI or VIP inspections, the applicant was requested to identify the sampling basis and inspection results for piping systems and components subject to layup conditions that have not been replaced. The staff identified this as an unresolved issue (URI). The staff discussed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups, as documented in subsequent applicant submittals.

The applicant's response, by letter dated May 18, 2005, clarified its response to RAI 3.0-9 by stating that a large amount of piping in the drywell and reactor building had been replaced, but the majority of the piping had been inspected and determined to be acceptable without replacement. The applicant submitted a table to identify the UT examinations performed to demonstrate that the existing piping has wall thickness in excess of the manufacturer's minimum nominal wall thickness (>87.5 percent of nominal) and did not require replacement. The non-replaced piping inspected included the RHRSW, fire protection, emergency equipment cooling water (EECW), raw cooling water (RCW), CRD, core spray, feedwater, HPCI, main steam, reactor core isolation cooling (RCIC), RHR, and RBCCW systems. The locations chosen for thickness examinations were susceptible areas that may have contained moisture during layup, or where engineering evaluation determined wear may have occurred. By letter dated May 27, 2005, the applicant submitted an additional clarification that the susceptible locations were those areas determined to have the highest potential for service-induced wear or latent aging effects, which include all types of corrosion. The applicant also clarified that the inspection techniques utilized evaluate internal conditions and are sensitive to the presence of unacceptable conditions including wear, erosion, corrosion, including crevice corrosion if present. By letter dated November 16, 2005, the applicant further clarified that visual and/or ultrasonic inspections establish the physical condition of systems and components not being replaced.

The staff reviewed the applicant's response and found the response acceptable. The applicant clarified that, for piping not replaced that was in a layup condition during the extended outage, UT examinations had been performed at susceptible locations having the highest potential for service-induced wear or latent aging effects to demonstrate that adequate wall thickness exists. There is reasonable assurance that a combination of internal visual inspections and UT inspection techniques applied are adequate to detect wear, erosion, and corrosion, including crevice corrosion. There is also reasonable assurance that the Corrective Action Program will continue to be applied to repair or replace degraded material identified in the inspections prior to adversely affecting the component intended function. Therefore, all issues related to the staff issue on replaced components are resolved.

3.7.1.3 Inspections Verification Programs for Layup and Chemistry Control

The SER with open items (OIs) issued on August 9, 2005, loosely used the terms “One-Time Inspection,” “Restart Inspection,” and “Periodic Inspection.” The ACRS, in its 526th committee meeting and subsequently in its Interim Report dated October 19, 2005, asked the staff to provide clarity on these inspection terms and for the final SER to correctly reflect the intent of the inspections to be performed. Accordingly, the staff sought clarifications on these terms. In its submittal, by letter dated November 16, 2005, the applicant provided the following definitions of the inspection terms and clarified its interpretation of these inspections in previous submittals (RAI 3.0-10 LP, responses to URIs 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP). The staff has since reviewed the SER with OIs and the final SER reflects the use of these definitions as provided below:

> <u>One-Time Inspection</u> - The applicant's One-Time Inspection Program, B.2.1.29, is consistent with GALL AMP XI.M32, "One-Time Inspection.” These inspections include measures to verify that unacceptable degradation of any reactor system component is

not occurring, validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation.

Restart Inspection - These inspections are used as a means of verifying the material conditions of the system(s) of interest prior to the Unit 1 restart. These are performed prior to restart. These inspections are implemented to return Unit 1 to operation for the remainder of the current licensed operating period. In its submittal, by letter dated November 16, 2005, the applicant stated that the restart program does not take credit for the layup in returning a system to operations and instead depends on inspections and/or replacement to ensure the components are satisfactory for the remainder of the current licensed operating period.

Unit 1 Periodic Inspections - These inspections are for Unit 1 systems that have been shutdown during the extended layup and that were not subsequently replaced as a part of the Unit 1 restart project. These are targeted periodic inspections that will be performed on chosen systems after Unit 1 is returned to operation. The intent is to verify the effectiveness of AMPs and to verify that no additional latent aging effects are occurring. The staff agreed that the results from the Unit 1 restart inspection can be used as a first set of data points. These inspections are periodic in nature and performed prior to and during the period of extended operation until the applicant determines that no unacceptable degradation is occurring. The applicant's Unit 1 Periodic Inspection Program is described in AMP.B.2.1.42.

Systems Maintained in Dehumidified Air - The staff reviewed information presented in LRA Table 1 supplement dated February 19, 2004, on wet layup and determined that additional information was required. In RAI 3.0-2 LP, dated August 23, 2005, the staff requested the following additional information on Table 1 components in dry layup.

For the systems covered by Table 1, the applicant stated that during layup, the systems were maintained in dehumidified air (60 percent relative humidity) and no additional aging effects were identified for the layup condition.

NRC Inspection Report 50-259/87-45 reported that in 1987 an acceptable program for monitoring the relative humidity of all pipe environments had not been finalized and the extent to which all parts of each system was being continually purged with dry air had not been established. For example, the standby liquid control system contained moisture in portions of the system and procedures did not require the system to be monitored for dryness. Although inadequacies in the program were later resolved, it appears that the moisture concerns existed for an extended period of time.

Also, industry documents such as EPRI NP-5106, "Sourcebook for Plant Lay-up and Equipment Preservation," revision 1, identify the need to monitor the effectiveness of the layup practices. This document states that relative humidity (RH) cannot be used alone as a layup surveillance technique to evaluate layup effectiveness.

Table 1 does not identify any additional inspections prior to Unit 1 restart to assess the condition of these systems, and it is not clear if inspections were performed in the layup condition. In light of the above inspection findings, the recommendations in the industry documents, and the possibility that parts of this system may not have been continually purged with dry air (such that the exact dryness of the surrounding air cannot be ascertained), discuss any inspections planned before startup to address the potential aging during the extended outage, and whether these inspections target system low points where condensate and/or chemicals could accumulate. If inspections have been performed recently, discuss the results of the inspections. If no inspections to verify the aging during the extended outage are planned, provide justification for not performing such inspections. Describe the process that was used to maintain equipment in a dry layup condition. Discuss how humidity was controlled and maintained below 60 percent, whether the 60 percent is relative to the coldest portion of the system, the results of any monitoring and trending of the air quality and humidity, and the corrective actions taken (including any inspections) for any conditions where the humidity criterion was exceeded (including corrective actions for the conditions identified in the above inspection report). Also, Table 1 identifies that future one-time inspections are planned. Discuss how the one-time inspections will differentiate between the rate of aging in the different environments (operation vs. shutdown), and discuss whether the one-time inspections will target locations that are susceptible to aging during normal operation or during shutdown.

In its response, by letter dated October 8, 2004, the applicant stated that, for components within the dry layup systems, a one-time inspection (restart, per letter dated November 16, 2005) will be performed prior to Unit 1 restart to verify the material condition. The applicant further stated that the One-Time Inspection Program does not differentiate between the rate of aging in different environments (i.e., normal power operation versus cold shutdown).

<u>Components in a Lubricating Oil Environment</u>. - In RAI 3.0-4 LP, dated August 23, 2004, the staff requested the following additional information for managing components exposed to a lubricating oil environment.

For components in a lubricating oil environment, the LRA identified no AERMs. The applicant was requested to discuss how the lubricating oil was maintained during the extended outage. The applicant was also requested to discuss whether testing was performed to verify the oil qualities, including moisture, that would affect aging. If the lubricating oil was drained, the applicant was requested to discuss the resulting environment and any applicable aging degradation. The applicant was further requested to discuss any planned inspections to verify that there was no significant aging during the extended outage.

In its response to RAI 3.0-4 LP, dated October 8, 2004, the applicant stated that no maintenance or testing was performed for the recirculation system lubricating oil environment during plant layup. However, this lubricating oil environment is being deleted by design change notice (DCN) 51219A, which replaces the recirculation pump MG sets with a variable frequency drive. This modification has been installed on Units 2 and 3 and will be installed on Unit 1 prior to restart.

The applicant further stated that no maintenance or testing was performed for the reactor core isolation cooling system or the HPCI system lubricating oil environment during plant layup.

However the applicant clarified that a sample of components with a lubrication oil environment within these systems will be inspected for the following aging effects by the One-Time Inspection Program.

- carbon and low-alloy steel – loss of material due to general corrosion, crevice corrosion, pitting corrosion, and galvanic corrosion
- stainless steel - loss of material due to crevice corrosion and pitting corrosion
- copper and copper alloys – loss of material due to crevice corrosion, pitting corrosion, galvanic corrosion, and selective leaching
- cast iron and cast iron alloys - loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, and selective leaching

<u>Systems Exposed to Air/Gas Environment</u> - In RAI 3.0-5 LP, dated August 23, 2004, the staff requested the additional information for systems exposed to an air/gas environment. Tables 2 and 3 show that some components are exposed to an air/gas internal environment during normal operation, but state that this environment is not applicable during the extended outage. These tables state that, due to drainage and system isolation, portions of several systems may have been exposed to an internal environment of moist air. These tables also state that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems. However, Tables 2 and 3 identify additional aging effects for moist air than they identify for treated water (for example, cracking in low points where condensation and chemicals can accumulate). Clarify the above discrepancy in Tables 2 and 3. Also, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated water environment, explain why the evaluation of the aging effects for the treated water environment would encompass that of the aging effects for a moist air environment in these systems. Tables 2 and 3 state that one-time inspections are planned for the components that are exposed to an air/gas internal environment. The applicant was requested to discuss the plans for additional inspections before startup of Unit 1 to evaluate aging during the extended outage, or inspections that were performed during the extended outage. If no such inspections are planned or none have been performed, provide justification that they are not needed and discuss how the one-time inspection will distinguish between the rate of aging in the different environments.

In its response to RAI 3.0-5 LP, dated October 8, 2004, the applicant stated that Table 2 Systems [RVIs, Feedwater (03), Reactor Vessel Vents and Drains (10), Reactor Recirculation (68), Reactor Water Cleanup (69) and Control Rod Drive (85)] and Table 3 Systems [Condenser Circulating Water (27), Gland Seal Water (37), Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)] address the portions of these systems laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double valves was considered the same, (i.e., treated water or raw water) as water flowing through the valves prior to closure. N/A (not applicable) denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant further stated that during layup the temperature of the systems addressed in Tables 2 and 3 were less than 140°F. Therefore, crack initiation and growth due to SCC is not a concern for stainless steels and nickel-based alloys in a wet layup environment.

The applicant clarified that the evaluation of these moist air environments for the systems addressed in Tables 2 and 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The LRA identified these trapped air environments for restart inspection because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material, but only to verify its material condition. The applicant stated that the inspection will be performed prior to Unit 1 restart.

Systems Not Part of Wet Layup Program - In RAI 3.0-6 LP, dated August 23, 2004, the staff requested the following additional information on systems that were not part of the wet layup program and were exposed to stagnant treated (non-controlled) or raw water.

Table 3 of Evaluation of BFN Unit 1 Lay-up and Preservation Program (submittal dated February 19, 2004) identifies several systems that were not incorporated into the Unit 1 wet layup program. These systems were exposed to treated (non-controlled) or raw water during the extended outage. Table 3 concluded that there is no additional aging management for these systems. The staff required additional information on the following: (1) discussion of the results of any water samples, including pH, oxygen levels, aggressive chemical species, biological activity, and corrosion product levels, (2) discussion whether the systems were stagnant or periodically flowed, (3) discussion whether the plans for prestartup inspections to determine the loss of material due to general, pitting, and crevice corrosion, MIC, dealloying, and galvanic corrosion, or provide justification that such inspections are not needed, and (4) also, discussion of inspections for the degradation of other materials, such as elastomers and other non-metallic materials.

In its response to RAI 3.0-6 LP, dated October 8, 2004, the applicant stated:

> Condenser Circulating Water System (27) - System 27 was exposed to Tennessee River water which is the same environment it is exposed to during normal operation. Without the addition of foreign chemicals the aging effects during normal operation and during layup are the same.
>
> Gland Seal Water System (37) - The system was drained (ambient air present) with the gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system were not completely drained. The applicant stated that therefore, stagnant treated water supplied from the condensate system was evaluated for these areas.
>
> Systems (Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75) - The torus and torus attached piping for System 64 (i.e., the torus itself) and for Systems 71, 73, and 75 (torus attached piping) saw torus water maintained by Chemistry Program CI-13.1, Appendix A, Table 20) for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not "flowing" in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit cannot be

considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. Torus coating touch-up/repair is part of the restart work to be completed while the torus is drained. The torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. µS/cm, 75 ppb, and 75 ppb, respectively. The applicant stated that a review of sampling data showed that the torus water was maintained within the chemistry specifications and that sampling is performed quarterly. In respect to these systems, the applicant will perform restart inspection prior to Unit 1 restart to verify the material condition.

Inspections to be Performed Prior to Restart - In RAI 3.0-7 LP, dated August 23, 2004, the staff requested the following additional information on Notes 1 and 2 of Tables 2 and 4 concerning inspections to be performed prior to the Unit 1 restart.

Notes 1 and 2 of Tables 2 and 4 indicate that a restart inspection will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended shutdown. Examples include additional aging effects for copper alloy, cast iron, cast iron alloy, and stainless steel components in system locations where condensation could build up, and carbon and low-alloy steel in an internal environment. No descriptions of the inspections were provided. The staff asked the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections.

The applicant responded to RAI 3.0-7 LP by stating that Note 1 of Tables 2 and 4 identifies the potential for external general corrosion on carbon and low-alloy steel components that are normally operated at temperatures greater than 212°F. This note is applicable to the reactor vessel (RV), feedwater system (03), and the heater vents and drains system (06). External surface monitoring is performed in accordance with the Systems Monitoring Program described in the LRA Section B.2.1.39. The applicant stated that this is the same AMP proposed for managing external loss of material during the period of extended operation.

The applicant also stated that Note 2 of Tables 2 and 4 identifies the potential for internal loss of material and cracking (aluminum only) that are normally exposed to either dry air or nitrogen. The applicant clarified that this note is applicable to the following systems and materials:

Feedwater (03)	Copper Alloy
Main Steam (01)	Aluminum Alloy
Containment Inerting (76)	Carbon and Low-alloy steel Stainless Steel Nickel Alloy Copper Alloy Aluminum Alloy Cast Iron

Containment Atmosphere Dilution (84)	Carbon and Low-alloy steel Stainless Steel Copper Alloy Aluminum Alloy Cast Iron

The applicant's response to RAIs 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP, by letter dated May 27, 2005, clarified that this is a restart inspection.

Management of Galvanic Corrosion - In RAI 3.0-8 LP, dated August 23, 2004, the staff requested the following additional information on management of galvanic corrosion with the water chemistry and one-time inspections.

The LRA and the supplement dated February 19, 2004, are not clear regarding the management of galvanic corrosion. There is the potential for galvanic corrosion during the extended outage for those systems that were maintained in wet layup, wet non-layup, or moist air such that condensation and pooling could occur. The LRA and Reference 2 state that galvanic corrosion is managed through use of the Chemistry Control Program and the One-Time Inspection Program; however, there were differences in water chemistry during the extended outage, and the One-Time Inspection Program does not cover galvanic corrosion. The applicant was requested to describe how galvanic corrosion during the extended outage is managed. The applicant was also requested to discuss any inspections that are planned to determine the extent of galvanic corrosion during the extended outage.

In its response to RAI 3.0-8 LP, dated October 8, 2004, the applicant stated that the Chemistry Control Program implemented during the extended outage is the same program that BFN uses on the two operating units during cold shutdown conditions for refueling and maintenance outages. This extended outage program would consist of CI-13.1 chemistry program controls, which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515). The applicant further stated that the One-Time Inspection Program utilized to verify the effectiveness of the Chemistry Control Program for preventing loss of material will select the susceptible locations (where materials with different electrochemical potentials are in contact in the presence of contaminants). Finally the applicant stated that galvanic corrosion is included in the One-Time Inspection Program.

In regard to SCC, the staff found the applicant's response to RAI 3.0-5 LP to be reasonable and acceptable, because the applicant clarified that during layup the temperature of the systems addressed in Tables 2 and 3 was less than 140°F in a wet layup environment; therefore, crack initiation and growth due to SCC is not a concern for stainless steels and nickel-based alloys. In Tables 2 and 3, SCC is correctly identified as an aging effect for stainless steel during plant operation at elevated temperatures and SCC is managed by various AMPs.

The staff reviewed the applicant's responses to the above RAIs and determined that additional information was required concerning the application of the One-Time Inspection Program as a verification program for layup and chemistry controls. By letter dated December 16, 2004, staff submitted RAI 3.0-10 LP requesting the applicant to provide additional information on one-time inspections.

The staff reviewed the applicant's responses to the above RAIs and determined that additional information was required concerning the application of the One-Time Inspection Program as a verification program for layup and chemistry controls.

In RAI 3.0-10 LP, dated December 16, 2004, staff stated that industry guidance on recovering plants placed in extended layups such as Browns Ferry specifically recommends that a surveillance and assessment program is needed to monitor the effects of outage or storage conditions on nuclear power plant components, otherwise, evidence of bad layup often will not even manifest itself until after a plant has returned to power. In pursuing this line of reasoning, the staff requested that the applicant clarify if one-time inspections may not be appropriate where degradation is expected to occur or occur very slowly. Specifically, for systems not associated with the BWRVIP program, the staff wanted the applicant to justify why a one-time inspection is appropriate for aging management in lieu of periodic inspections. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify that no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period, and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

These staff dialogues and the ACRS interim report, dated October 19, 2005, led to the development of a new plant-specific AMP B.2.1.42, “Unit 1 Periodic Inspection Program,” for BFN Unit 1 components that will not be replaced before restart.

3.7.1.4 MIC

In RAI 3.0-3 LP, the staff requested the following additional information on MIC:

> Industry documents such as EPRI NP-5106, indicate that all metals are susceptible to MIC, especially in stagnant and low flow areas, and microbes in the system should be monitored by an adequate program at least every week and more often in outages. NRC Inspection Report 50-259/87-45 identified damage due to MIC had already occurred in the fire protection system and water samples in the demineralized water system were planned. Table 2 does not identify MIC as a corrosion mechanism (for example, in the RWCU and CRD systems for systems intended for wet layup with demineralized water. Table 3 does not identify MIC as a corrosion mechanism for systems that had no water

chemistry control (wet, non-layup) during the extended outage. Similarly, Table 4 does not identify MIC as a corrosion mechanism for components subject to a moist air environment for extended periods of time. Provide technical justification that MIC is not an aging mechanism applicable to the stagnant, low flow, and moist air portions of the mechanical systems. Alternatively, describe how inspections would detect loss of material caused by MIC at susceptible locations.

In its response to RAI 3.0-3 LP, by letter dated October 8, 2004, the applicant stated:

Table 2 contains Systems [Reactor Vessel and Internals (RVI), Feedwater (03), Reactor Vessel Vents and Drains (10), Reactor Recirculation (68), Reactor Water Cleanup (69) and Control Rod Drive (85)] laid up with demineralized water maintained by the Chemistry Program CI-13.1 and moist air from possible pooling of Chemistry Program CI-13.1 controlled treated water between drain valves and double isolation valves due to closure sequence, closure timing, and possible leaking past the valves. Although portions of these systems had stagnant, low flow, and moist air environments, the Chemistry Program prevented the presence of microbes necessary to cause MIC damage. A review of BFN PERs and Work Orders (WOs) (operating experience) did not identify MIC as a concern in treated water.

Table 3 contains Systems [Condenser Circulating Water (27), Gland Seal Water (37), Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)].

1. MIC is identified as a concern for raw water environments regardless of flow rate in the Condenser Circulating Water System (27).
2. The laid up environment for the Gland Seal Water System (37) was treated (condensate) water and moist air from possible pooling of treated water between drain or isolation valves and in the loop seals. BFN operating experience did not identify MIC as a concern in treated water environments. Although there were no chemistry controls placed on system 37 during layup, raw water or other MIC agents were not introduced into this system. Therefore, the microbes necessary for the propagation of MIC were not present in this system during layup.
3. Treated (torus) water was maintained by the Chemistry Program CI-13.1 during wet layup. The portions of Systems [Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)] within the BFN LR scope (torus and torus attached piping) during Unit 1 layup had a treated water environment and moist air from possible pooling of treated water (torus water) between drain valves and double isolation valves due to closure sequence and timing and possible leaking past the valves. Although portions of these systems had stagnant, low flow, and moist air environments, the Chemistry Program CI-13.1 prevented the presence of microbes necessary to cause MIC damage. A review of BFN PERs and WOs (operating experience) did not identify MIC as a concern in treated water.

Table 4 Systems [Main Steam (01), Condensate (02), Heater Drains and Vents (06), Containment Inerting (76), and Containment Atmosphere Dilution (84)] contained treated water or nitrogen prior to Unit 1 layup. These systems were drained during layup. These systems were isolated without the introduction of raw water or other MIC agents. Therefore, the microbes necessary for the propagation of MIC were not present in these systems during layup.

In a follow up to the general RAI 3.0-10 LP, dated December 16, 2004, the applicant was requested to clarify why one-time inspections are appropriate for locations with stagnant, low flow or intermittent flow where MIC is expected on the basis of industry operating experience due to possibly ineffective chemistry control in these regions. The applicant was asked to identify the results of any inspections performed in low flow or stagnant areas to demonstrate that aging effects are not expected to occur or are expected to occur slowly. The applicant was also requested to provide information on any corrosion monitoring programs for MIC, including augmented inservice inspection of susceptible areas and corrosion coupons or spool pieces. Otherwise, the applicant should consider the application of periodic inspections to evaluate aging effects in these areas.

In the response provided by the applicant to RAI 3.0-10 LP, the staff's concerns relevant to MIC were not addressed. The staff was concerned that various corrosion mechanisms that would not be active during operation often appear during layup, as water chemistry controls may not be as stringent, particularly in stagnant areas. Industry documents such as EPRI NP-5580, “Sourcebook for Microbiologically Influenced Corrosion in Nuclear Power Plants,” indicate that additions of corrosion inhibitors and biocides made after layup are unlikely to be effective, as distribution throughout the system is limited. EPRI NP-5580 also indicates that proper attention to layup is crucial to avoid MIC and during layup, microbial growth may proceed unimpeded as fluid forces that remove attached organisms from pipe or vessel surfaces are absent. Staff is also concerned that corrosion mechanisms that were not active during dry layup may become active when the systems are wetted and returned to operation. To complete its review, the staff again requested the additional information previously requested in RAI 3.0-10 LP, on inspections performed or planned to determine that MIC is not a concern for systems subject to conditions that promote MIC. The staff originally proposed this as URI 3.0-5 LP. The staff discussed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups and subsequent applicant submittals.

By letter dated May 27, 2005, the applicant referenced the response to RAI 3.0-10 LP included in letter dated May 18, 2005, to address MIC. In the applicant's response by letter dated May 18, 2005, the applicant clarified that the raw water piping is susceptible to MIC and the primary method used for MIC control is routine injection of biocides. The applicant stated that this treatment method has been effective in controlling MIC for in-service raw water piping. For systems not in service during the extended outage the piping was inspected and evaluated. The applicant stated that the majority of the raw water piping was in a dry layup condition and has been inspected and found to have adequate wall thickness, with two exceptions. As identified by the applicant, the portions of the RHRSW system in the reactor building that contained moisture required replacement due to inadequate wall thickness. Similarly, approximately 3,000 feet of large bore and small bore RCW piping requires replacement due to inadequate wall thickness.

The staff reviewed the applicant's response and found the response acceptable. The applicant clarified that raw water piping susceptible to MIC during the extended outage has either been replaced or inspected to verify that adequate wall thickness exists. In addition, there is reasonable assurance that the mitigative programs will be effective to preclude future MIC and potential latent aging effects due to MIC in all systems subject to layup during the extended outage, including systems containing raw water, will be detected and corrected by future periodic inspections. All issues related to RAI 3.0-5 LP are resolved.

3.7.1.5 Transition from Layup Program to System Cleanliness Verification Program

The system cleanliness verification program is not addressed in the LRA nor in February 19, 2004, letter containing the attachment, "Evaluation of BFN Unit1 Layup and Preservation Program." NRC quarterly integrated inspection report 05000259/2004006 states that on March 22, 2004, the applicant decided to remove all Unit 1 systems from layup. This decision was based on the need to transition to a system Cleanliness Verification Program. According to NRC quarterly integrated inspection report 05000259/2004007, this program is intended to replace the previous equipment layup program that has been in place since the unit was shutdown. This report also stated that, under the new program, the assigned system and component engineers, along with chemistry personnel, would perform a series of inspections of Unit 1 systems to identify any system degradation or special requirements to support Unit 1 recovery. It is the staff's understanding that transition to the newer program was still in progress at the time of the inspection period on July 10, 2004.

In RAI 3.0-11 LP, dated December 16, 2004, the applicant was requested to clarify if this series of inspections is part of the One-Time Inspection Program that is going to be implemented prior to Unit 1 restart. If the one-time inspections are different from or in addition to the cleanliness verification program inspections, the applicant was requested to so clarify. Also, it is not clear to the staff if this system cleanliness verification program includes inspections on components that were replaced or repaired. The applicant was requested to provide additional information as to what type of inspections have been or will be performed by the system Cleanliness Verification Program (CVP).

In its response to RAI 3.0-11 LP, the applicant stated that inspections performed under the CVP are not part of the one-time LRA inspections or credited as part of the license renewal application. The applicant clarified that to facilitate Unit 1 restart activities, Unit 1 systems have been removed from the layup program. It is not possible to maintain the layup program and perform the required field work needed for restart of Unit 1.

The applicant stated that the purpose of the CVP is to (1) verify, through cleanliness verification of all internal and external surfaces of piping systems and metallic components, that the requirements for fluid (gas or liquid) system internal and external cleanliness are in accordance with TVA and industry standards; and (2) provide the detailed remedial cleaning instructions for internal and external surfaces of piping systems and metallic components whose internal and external surface cleanliness does not meet respective cleanliness criteria as a result of extended layup, or work activity.

The CVP activities are applicable to all Unit 1 steam, water, air, gas and oil piping systems and components that receive a formal return to service in accordance with the Unit 1 Restart Test Program System Preoperational Checklist. The applicant clarified that the only Unit 1 systems excluded from this program are those that are currently in service or have been in service supporting Units 2 and 3.

The applicant also stated that CVP inspections are performed to ensure internal and external system cleanliness and that foreign material control program requirements are met. Visual inspections aided by boroscopes are performed to identify any needed remedial cleaning or flushing activities. If inspection reveals evidence of piping degradation, a problem evaluation report is initiated and entered into the Corrective Action Program. An engineering evaluation is performed to ensure that the system is capable of operation through the extended period. The applicant further stated that the inspections performed by the CVP are not a part of the one-time LRA inspections; nor are they a part of the license renewal process.

The staff reviewed the applicant's response to RAI 3.0-11 LP and found that the response is reasonable and acceptable because the applicant provided sufficient information on system cleanliness inspections and clarified that cleanliness inspections are different from the one-time inspections credited for license renewal. The applicant credits visual inspections aided by boroscopes to detect and correct degradation during the transition period between layup and restart. Both external and internal inspections are performed to industry standards as part of the system Cleanliness Verification Program. Internal inspections to recognized industry standards should be adequate to detect degradation during the transition period between layup and restart.

3.7.2 Reactor Vessel internals and Reactor Coolant System

3.7.2.1 Reactor Recirculation System (068)

Summary of Technical Information in the Application.

The applicant provided a summary of its evaluation of the Unit 1 layup and preservation program in LRA Section 3.0.1. The applicant's specific AMRs for the reactor recirculation system (068) of Unit 1 that are exposed to wet layup environment are given in Table 2 of the applicant's letter, "Evaluation of the BFN Unit 1 Lay-up and Preservation Program," Revision 1, dated February 19, 2004. The applicant identified several aging effects of the applicable materials of the reactor recirculation system that are exposed to the wet layup environment. These components extend from the reactor vessel outlet nozzle, through the valves and pumps, to the reactor vessel inlet nozzle. Also included are components within the reactor recirculation motor generator set oil system and instrument tubing and piping outside the drywell.

In Section 4.0 of chapter "Mechanical System/Program Evaluation Detail-Wet Layup Program Unit 1" of the February 19, 2004, letter, the applicant identified the following aging effects associated with stainless steel, carbon steel, and copper-alloy materials that are exposed to a treated-water environment during the wet layup period of Unit 1.

- general corrosion
- crevice corrosion
- pitting corrosion
- galvanic corrosion
- selective leaching

In Table 2, "Evaluation of BFN Unit 1 Layup and Preservation Program," Revision 1, the applicant provided a summary of AMRs for the reactor recirculation systems of Unit 1 that are within the boundary of the wet layup program. These AMRs are not addressed in the GALL Report. The staff also identified areas where additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included below.

<u>Crevice and Pitting Corrosion</u>. The staff, after the review of the applicant's submittal, determined that aging effects due to crevice and pitting corrosion of the reactor recirculation system, are possible unless stringent control on the RCS water is implemented during the wet layup period. The aging effects due to crevice and pitting corrosion on the reactor recirculation system materials (i.e., carbon steel, stainless steel, and copper-alloy materials) can be more pronounced when they are exposed to stagnant conditions during the wet layup rather than the regular service condition. The applicant stated that the reactor recirculation system materials will experience crevice and pitting corrosion when the dissolved oxygen content in the RCS water exceeds 100 ppb, and the choride and sulphate contents exceed and 150 ppb with stagnant or low flow conditions during the wet layup period. In Table 2 of the applicant's submittal, "Evaluation of the BFN Unit 1 Lay-up and Preservation Program," Revision 1, the applicant claims that it will manage this aging effect by CI-13.1 Chemistry Control Program. The cold shutdown impurity limits for conductivity, chloride, and sulfate given in CI-13.1 (1.5. µS/cm, 15 ppb, 15 ppb) are more restrictive than those given in the EPRI BWR Water Chemistry Guidelines (TR-103515-R2, page 4-6, Table 4-2) for "Reactor Water - Cold Shutdown." The staff found that the implementation of the Chemistry Control Program would enable the applicant to subsequently mitigate the crevice and pitting corrosion in the reactor recirculation system components.

<u>Selective Leaching</u>. The staff, after the review of the applicant's submittal, determined that the aging effect due to selective leaching of reactor recirculation system components fabricated from copper-alloy material used in a treated-water environment require aging management for selective leaching for the period of extended operation for the Unit 1 layup systems. The applicant stated that copper-zinc alloys containing greater than 15 percent zinc in a treated-water environment are susceptible to selective leaching, while copper alloys with a copper content in excess of 85 percent resist dezincification. The applicant currently credits the One-Time Inspection Program and the Selective Leaching of Materials Program; but, requires no additional aging management of Unit 1 due to the wet layup condition as shown in Table 2 of its February 19, 2004, letter. The staff found this acceptable because the One-Time Inspection Program and Selective Leaching Program will be just as effective to detect and manage selective leaching on the Unit 1 wet layup systems as it is on systems not in wet layup in BFN.

<u>Loss of Material Due to General Corrosion</u>. General corrosion of carbon and low-alloy steel in treated water is an aging mechanism that must be managed for the period of extended operation for the Unit 1 layup Systems. The applicant identified the Chemistry Control Program, the One-Time Inspection Program and ASME Section XI Subsections IWB, IWC and IWD Inspection Program. The Chemistry Control Program mitigates general corrosion by minimizing dissolved oxygen, thus, reducing the effect of general corrosion as an internal aging effect. The applicant’s one-time inspection will ensure that general corrosion has been controlled and the ASME Section XI inspections will ensure that the affected components continue to perform their required function during the period of extended operation.

<u>Loss of Material Due to Galvanic Corrosion</u>. Galvanic corrosion of carbon and low-alloy steel in treated water is an aging mechanism that must be managed for the period of extended operation for the Unit 1 layup systems. The applicant identified the Chemistry Control Program,

the One-Time Inspection Program, and ASME Section XI Subsections IWB, IWC and IWD Inspection Program. The Chemistry Control Program minimizes galvanic corrosion by controlling dissolved oxygen, chlorides, conductivity, and PH. The applicant's one-time inspection will provide verification that galvanic corrosion has been managed during the Unit 1 wet layup period and the ASME Section XI inspections will ensure that the affected components continue to perform their required function during the period of extended operation.

As a result of the Unit 1 restart efforts, the applicant is in the process of replacing several components and is conducting numerous inspections. Below is a description of some of the restart efforts that impact the recirculation system and provide additional confidence that Unit 1 will be adequately managed so that the intended functions of the reactor recirculation system are maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Recirculation System Piping. During the restart efforts on Unit 1, several components will be replaced, obviating the need to be concerned about degradation of these components during the wet-layup period. In RAI 3.1.2.4-6, dated December 1, 2004, the staff requested that the applicant discuss whether the recirculation system piping had experienced any cracking in the past. The applicant responded in part that no recirculation system piping welds less than NPS 4 were identified as having cracking or crack indications in the inservice records. The applicant also stated that during the Unit 1 recovery efforts the recirculation system piping greater than NPS 4 is being replaced with IGSCC-resistant piping (316NG or 316L). According to the applicant, this includes all welds that it identified as having IGSCC indications. In order to clarify the extent of piping replacement in the reactor recirculation system, the staff requested the applicant to discuss replacement of piping less than NPS 4 in a follow up to RAI 3.1-1. The applicant responded by letter dated January 20, 2005, and stated that all piping of the reactor recirculation system (068) is being replaced with the exception of small sections of the 3/4-inch and 1-inch piping on each side of the system 068 penetrations on LR drawing 1-47E817-1-LR.

Heat Exchangers. All heat exchangers that are not being replaced due to design changes are being inspected. Inspection will include 100 percent eddy current testing of tubes. SR heat exchangers will have their shell casing ultrasonically tested for thickness. The applicant also stated that visual inspections of the heat exchangers for pitting or erosion are performed when manway covers are removed or the connecting piping is replaced.

Valves. Valves within the piping systems were reviewed to determine whether the valves needed to be replaced or refurbished. During the Unit 1 restart effort, approximately 3000 valves will be replaced. The applicant also estimated that approximately 1000 valves will be tested and refurbished.

Conclusion. The staff, after reviewing the applicant's submittal, concluded that the aforementioned aging effects do not cause any additional degradation of components in the reactor recirculation system during the wet layup period at Unit 1. The staff believes that the relevant critical variables that may cause any additional degradation due to these aging effects are adequately managed during the wet layup period. If by chance some additional degradation occurred in the reactor recirculation system, the applicant's restart activities should be effective in identifying and correcting issues prior to start up.

3.7.2.2 Reactor Vessel (RV), Reactor Vessel Internals (RVIs)

Summary of Technical Information in the Application.

The applicant's specific AMRs for the RV and RVIs at Unit 1 that are exposed to the wet layup environment are given in Table 2 of the applicant's supplemental submittal, dated February 19, 2004, "Evaluation of the Unit 1 Layup and Preservation Program, Revision 1." The applicant identified several aging effects applicable to the materials in the RV and RVIs that are exposed to the wet layup environment during the extended outage.

The components in the RV and RVIs include RV attachment welds, reactor closure studs and nuts, RV heads, flanges and shells, RV nozzles and safe ends, RV penetrations, RVIs core shroud and core plate, RVIs core spray lines and spargers, RVIs dry tubes and guide tubes and RVIs jet pump assemblies.

In Section 4.0 of the supplemental submittal dated February 19, 2004, the applicant evaluated the following aging effects that are associated with stainless steel materials when they are exposed to RCS treated-water environment during the wet layup period at Unit 1.

- pitting corrosion
- crevice corrosion
- MIC
- SCC
- thermal aging
- neutron embrittlement
- stress relaxation
- particulate fouling

Technical Staff Evaluation of Aging Effects

In Table 2 of the supplemental submittal dated February 19, 2004, the applicant provided a summary of AMRs for the RV and RVIs at Unit 1 that are within the boundary of the wet layup program. These AMRs are not addressed in the GALL Report. The staff also identified several areas where additional information or clarification was needed. The staff issued RAIs to the applicant regarding the wet layup issues. The staff's evaluation of the applicant's submittal and its responses to the RAIs are addressed below.

Pitting and Crevice Corrosion. The staff, after the review of the applicant's submittal, determined that the aging effects due to pitting and crevice corrosion of the RCS pressure and non-pressure boundary components could have been significantly affected during the wet layup period, unless stringent control on the RCS water was implemented during the wet layup period. The RVs and RVIs could have been subjected to more frequent stagnant conditions during the wet layup period than during regular service conditions. Therefore, aging effects due to pitting and crevice corrosion on the RV and RVIs materials can be more pronounced when they are exposed to stagnant conditions during the wet layup period. The applicant stated that the RV materials may have experienced pitting when the RCS water dissolved oxygen concentration exceeded 100 ppb and the chloride or sulfate concentrations exceeded 150 ppb during the wet layup period. However, crevice corrosion could have occurred when the dissolved oxygen content in the RCS water exceeded 100 ppb. In Table 2 of the submittal, the applicant stated that it managed these aging effects by CI-13.1 Chemistry Program. The cold shutdown impurity limits for conductivity, chloride and sulfate given in CI-13.1 [1.5 µS/cm), 15 ppb, 15 ppb] are more restrictive than those given in the EPRI BWR Water Chemistry Guidelines (TR-103515-R2, page 4-6, Table 4-2). These guidelines are applicable for RCS water when the plant is in cold shutdown condition.

In RAI 3.0-1 LP(a), the staff requested that the applicant identify the differences between the chemistry program(s) implemented in the RCS system during the wet layup period at Unit 1 and the chemistry program to be implemented in the RCS system at Unit 1 during the period of extended operation.

In its response to NRC RAI 3.0-1 LP(a), by letter dated October 8, 2004, the applicant stated that the RCS water was monitored for conductivity, chloride and sulfate concentrations in accordance with the requirements of CI-13.1. The chemistry control limits implemented during the wet layup period at Unit 1 are the same as the chemistry control limits utilized by Units 2 and 3 during cold shutdown conditions for refueling and maintenance outages. The selected BFN impurity limits are consistent with the limits for cold shutdown that are contained in BWRVIP-79, "BWR Water Chemistry Guidelines," (EPRI Report TR-103515-R2, February 2000), which is consistent with the GALL AMP XI.M2, "Water Chemistry," and the Chemistry Control Program. The chemistry program implemented during the period of extended operation for Unit 1 is the same program as that for Units 2 and 3 during power operation conditions.

The staff reviewed the response and found that implementation of a Chemistry Control Program that is more restrictive than GALL AMP XI.M2, would enable the applicant to mitigate pitting corrosion effectively in the RV and RVIs during the wet layup period at Unit 1.

The staff contended that if the dissolved oxygen content exceeded 100 ppb during the wet layup period, crevice corrosion of the RVIs could have occurred. In order to ensure that crevice corrosion is not occurring in the RV and RVIs, the staff requests that the applicant confirm that the dissolved oxygen content in the RCS water did not exceed 100 ppb during the wet layup period. This staff issue was resolved by the applicant’s subsequent response and submittals (see SER Section 3.7.2.2 below).

In RAI 3.0-1 LP(b), the staff requested that the applicant discuss the criteria (e.g., guidelines) used to maintain the chemistry of the fluid in the wet layup systems, the chemistry parameters monitored, and the frequency of the monitoring/trending.

In its response to RAI 3.0-1 LP(b), by letter dated October 8, 2004, the applicant stated that during the wet layup period reactor water was monitored in accordance with the requirements specified in Table 5 of the CI-13.1. The impurity limits for conductivity, chloride, and sulfate given in CI-13.1 were 1.5. µS/cm, 15 ppb and 15 ppb, respectively. The applicant also stated that sampling was performed once every two weeks, and the monitoring and trending results demonstrated that the RCS water was maintained within its impurity limits during the wet layup period.

Since the verification frequency of the RCS water chemistry is once every two weeks during the wet layup period, the staff determined that pitting and crevice corrosion in the RV and RVIs can occur if they are exposed to higher concentrations of chlorides and sulfates due to a leak in the primary systems. The staff issued follow-up RAI 3.0-1 LP (b), requesting that the applicant provide information regarding its past experience related to any sudden increase in concentration of chlorides and sulfates in the RCS water during the wet layup period, and the corrective actions taken to prevent impurities migrating into crevices in the RV and RVIs. The staff further requested that the applicant identify the crevice locations in the RV and RVIs that will not be replaced and where accumulation of aggressive ions such as chlorides and sulfates inside the crevice could have enhanced the likelihood of pitting and crevice corrosion during the wet layup period at Unit 1. The staff also requested that the applicant provide information regarding the type of inspection it intends to use in identifying the aging effects due to pitting and crevice corrosion in the RV and RVIs prior to Unit 1 restart and during the extended period of operation.

In its response to follow-up RAI 3.0-1 LP(b), by letter dated January 31, 2005, the applicant stated that during the wet layup period at Unit 1, the RCS water was operated as a closed-loop system using the RWCU system. Impurities (i.e., chlorides and sulfates) in the make-up water system at Unit 1 can potentially contaminate the RCS water. Condensate water was used for make-up water. If any impurities were detected, a new ion exchange resin would be applied to the RWCU system demineralizer. Since the RCS water would be processed approximately 1.5 times a day through the RWCU system, the applicant claimed that verification of RCS water chemistry every two weeks would be adequate in detecting the impurities. The applicant found no occurrences of sudden increase in concentration of impurities (i.e., chlorides and sulfates) in the RCS water during the wet layup period at Unit 1. The applicant stated that the impurities were maintained at acceptable levels (< 15 ppb) during the wet layup period. Based on stringent chemistry control, the applicant claimed that the RV and RVIs were less susceptible to pitting corrosion during the wet layup period. The applicant also proposed to perform inspections (discussed below) on the RV and RVIs prior to Unit 1 restart.

The staff reviewed the response and found it acceptable because the applicant implemented a Chemistry Control Program that is more restrictive than GALL AMP XI.M2. Since the impurities (i.e., chlorides and sulfates) in the RCS water were kept below the acceptable levels of 15 ppb, the RV and RVIs were less susceptible to pitting during the wet layup period.

In RAI 3.1-3 LP, the staff requested that the applicant provide details on any inspection plans for the RV and RVIs prior to Unit 1 restart.

In its response to RAI 3.1-3 LP, by letter dated August 23, 2004, the applicant stated that the RV and its components will be inspected in accordance with the requirements of the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program. The RVIs will be inspected in accordance with the requirements of relevant BWRVIP guidelines. The following list includes the RVIs and the applicable BWRVIP reports approved by the staff (with the exception of BWRVIP-76).

- BWRVIP-18-----Core Spray
- BWRVIP-25-----Core Plate
- BWRVIP-26-----Top Guide
- BWRVIP-27-A--Standby Liquid Control
- BWRVIP-38-----Shroud Support
- BWRVIP-41-----Jet Pump

- BWRVIP-47-----Lower Plenum (CRD, Incore)
- BWRVIP-48---- Vessel Attachment Welds
- BWRVIP-49-----Instrumentation Penetrations
- BWRVIP-76-----Core Shroud (under staff's review)

The applicant stated that the core shroud access hole covers will be examined in accordance with GE SIL 462, Revision 1. The applicant stated that the access hole covers for Unit 1 are cracked essentially 360 degrees around and will be replaced prior to Unit 1 restart.

The staff reviewed the response and found it acceptable because of the implementation of the ISI program, which is an established AMP that is based on compliance with the staff's ISI requirements in 10 CFR 50.55a. This program has appropriate requirements for inspecting the RV components prior to Unit 1 restart. The RVIs will be inspected in accordance with the requirements of applicable BWRVIP guidelines, thus enabling the applicant to identify pitting corrosion in the RVIs in a timely manner so that proper corrective actions could be taken to ensure their structural integrity prior to Unit 1 restart.

The staff's position is that if the dissolved oxygen content exceeds 100 ppb during the wet layup period, crevice corrosion of the RVIs could occur. In order to ensure that crevice corrosion is not occurring in the RV and RVIs, the staff requests that the applicant confirm that the dissolved oxygen content in the RCS water did not exceed 100 ppb during the wet layup period (Unresolved Item 3.7.2.2-1 in the applicant's response dated May 27, 2005). The staff followed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups and subsequent applicant submittals.

To confirm that the crevice locations in RVIs are not susceptible to corrosion, the staff requests that the applicant identify these locations and provide information as to how it uses the applicable BWRVIP inspection guidelines to detect any crevice corrosion of the RVIs prior to Unit 1 restart. (Unresolved Item 3.7.2.2-2 in the applicant's response dated October 13, 2005).

In its response, by letter dated May 27, 2005, the applicant indicated that during the wet layup period the RCS water was open to the atmosphere; therefore, the dissolved oxygen content in RCS water was expected to increase to 8 ppm. The staff requested that the applicant provide information regarding the implementation of the BWRVIP inspection guidelines to detect crevice corrosion of the RVIs prior to Unit 1 restart. In its response, the applicant also listed the following systems that have crevice type configurations, and proposed to implement appropriate BWRVIP inspection guidelines to monitor the aging effect due to crevice corrosion in these systems. The systems with crevice configuration include: (1) core spray; (2) jet pump assembly; (3) top guide; (4) control rod guide, and (5) core plate. The staff found the applicant's response acceptable because the inspection frequency and the inspection techniques specified in the respective BWRVIP guidelines, and the augmented inspection for the top guide (see TLAA SER Section 4.2.8.2) will adequately identify the crevice corrosion in the RVIs components so that corrective actions can be taken prior to Unit 1 restart, and after inservice inspection in accordance with BWRVIP guidelines. The staff considers these issues resolved.

Conclusion. The staff, after reviewing the applicant's submittal, and its responses to RAIs, concluded that the aging effect due to pitting corrosion had not caused any degradation of the RV and RVIs during the wet layup period at Unit 1. If any additional degradation occurred due to pitting corrosion in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart. The staff concluded that the aging effect due to crevice corrosion in the RVs and RVIs during the wet layup can be ascertained.

The applicant stated that the following aging effects are less likely to occur in the RV and RVIs and, as such, they do not require an AMP. This assessment was based on the fact that the conditions (stated below for each aging effect) in the RV and RVIs are less conducive for these aging effects to cause any degradation during the wet layup period.

- MIC
- SCC
- thermal aging
- neutron embrittlement
- stress relaxation

<u>MIC</u>. In Table 2 of the submittal, the applicant stated that MIC is unlikely to occur in treated water systems where sulfates are less than 150 ppb, and at temperatures greater than 210°F or pH greater than 10. The applicant claimed that Unit 1 layup systems contain treated water with little or no contamination. A review of BFN's work orders identified no instances where MIC was a failure mechanism for any components in the scope of license renewal for the RV and RVIs. The applicant stated that the RV and RVIs will not be affected by the aging effect due to MIC during the wet layup period. Based on the review of the submitted information, and in the absence of any evidence that indicates contamination in Unit 1 systems during the wet layup period, the staff believes that the RV and RVIs have not degraded due to MIC during the wet layup period at Unit 1.

<u>Stress Corrosion Cracking</u>. In Table 2 of the applicant's submittal, the applicant stated that for treated-water environments, stainless steel and nickel alloys are susceptible to SCC in the presence of chlorides or sulfate concentrations greater than 150 ppb and when the dissolved oxygen exceeds 100 ppb at temperatures greater than 140°F. The applicant claimed that limiting the chloride and sulfate concentrations to less than 150 ppb, and the dissolved oxygen to less than 100 ppb eliminates the potential for SCC of the stainless and nickel alloys' internal surfaces. The normal temperature of the RV systems is less than 140°F during the wet layup period. The applicant concluded that the RV and RVIs have not degraded due to SCC during the wet layup period.

In NRC RAI 3.0-1 LP b(4), the staff requested that the applicant provide information related to any addition of hydrogen inside the vessel and RCS systems to reduce the oxidizing nature of RCS water, which in turn reduces the occurrence of SCC of the RV and RVIs. In its response to RAI 3.0-1 LP b(4), by letter dated January 31, 2005, the applicant stated that no hydrogen was added to any of the RCS systems during the wet layup period. However, hydrogen will be added to the RCS systems during normal power operation at Unit 1. The staff found that the applicant's response is acceptable because during the wet layup period, the temperature of the RV and RVIs was less than 140°F; therefore, the RVI and RVIs were less likely to experience SCC.

In RAI 3.0-1 LP b(5), the staff requested that the applicant provide information related to the measurement of ECP of the reactor coolant, which will provide information on the oxidizing nature of the RCS water. In its response to RAI 3.0-1 LP b(5), by letter dated January 31, 2005, the applicant stated that no ECP measurements were made during the wet layup period. Since the RCS temperature is kept below 140°F during the wet layup period, aging effects of the RV and RVIs due to SCC is less likely. The staff found that the applicant's response of not measuring ECP values of the RCS water during the wet layup period is acceptable because SCC is less likely to occur when the RCS temperature was kept below 140°F during the wet layup period at Unit 1.

Thermal Aging. The applicant stated that wrought austenitic stainless steel is not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments. However, CASS materials are susceptible to thermal embrittlement depending upon material composition and time at high temperatures. CASS materials subjected to temperatures greater than 482°F are susceptible to thermal aging. The normal temperature of the RCS system during the wet layup period at Unit 1 is less than 482°F; therefore, the applicant claimed that CASS materials did not experience degradation due to thermal aging during the wet layup period. The staff, after the review of the submittal, concluded that the CASS materials did not degrade due to thermal aging during the wet layup period.

Neutron Embrittlement. The applicant stated that the carbon and low-alloy steel RV beltline region of the Unit 1 was not subjected to neutron fluence during the wet layup period; therefore, the degradation due to neutron embrittlement is not considered a potential aging effect. The staff agrees with this disposition, and concluded that the RV beltline region did not degrade due to neutron embrittlement during the wet layup period.

Stress Relaxation. The applicant stated that stress relaxation is a potential aging mechanism for bolting/fasteners with the RV and RVIs. The applicant claimed that the bolting/fasteners did not degrade due to stress relaxation during the wet layup period. The staff believes that during the wet layup period at Unit 1 the bolting/fasteners were not subject to any service-related loading conditions; consequently, they did not experience degradation due to stress relaxation.

Conclusion. The staff, after reviewing the applicant's submittal and its responses to RAIs, concluded that the aging effect due to pitting corrosion did not cause any degradation of the RV and RVIs during the wet layup period at Unit 1. If any additional degradation occurred due to pitting corrosion in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart. The staff concluded that the aging effect due to crevice corrosion in the RVs and RVIs during the wet layup can be ascertained.

The staff, after reviewing the applicant's submittal, concluded that other aging effects did not cause any degradation in the RV and RVIs during the wet layup period at Unit 1. The staff believes that the relevant critical variables that cause any degradation due to these aging effects were adequately controlled during the wet layup period. These critical variables include reactor water temperature, RCS water chemistry, neutron fluence and any service-induced loading conditions. Based on the information provided by the applicant thus far, the staff concluded that these critical variables stayed dormant and did not cause any degradation of the RV and RVIs during the wet layup period. If any additional degradation occurred in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart.

3.7.3 Engineered Safety Features

3.7.3.1 Engineered Safety Features Systems in Dry Layup

3.7.3.1.1 High Pressure Coolant Injection System

Technical Staff Evaluation. The technical staff reviewed the AMR of the HPCI system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The HPCI system is described in LRA Section 2.3.2.3. LRA Table 3.2.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 HPCI system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal described the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 1 of the applicant's February 19, 2004, supplement on wet layup provides the AMR of the HPCI system components within the scope of license renewal and was maintained in dry layup conditions. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifices, strainers, tanks, traps, tubing, turbines, and valves.

The February 19, 2004, submittal describes the internal environment of the system as being maintained at less than 60 percent RH de-humidified air. The external environment was inside air.

For the Unit 1 HPCI system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. Cast iron and cast iron alloy components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. Elastomer components in inside air (external) environments are subject to hardening and loss of strength due to elastomer degradation. No aging effects are identified for stainless steel, nickel-alloy, and copper-alloy components in air/gas (internal) or inside air (external) environments. No aging effects are identified for glass components in inside air (external) environments. No aging effects are identified for elastomers in air/gas (internal) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 1 of the February 19, 2004, submittal, for the HPCI system (73) and core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) or inside air (external) environments are subject to general corrosion during the period of extended outage. In the LRA AMR, the same aging effect is also identified for the same components in air/gas (internal) and inside air (external) environments. Because of the uncertainty of the dryness of air environments, the staff requested, in RAI 3.2-1

LP, the applicant to assure that the above layup air environments for these components are not any more aggressive than their counterparts in the plant operating environments, and that no additional aging effects would need to be considered. By letter dated October 8, 2004, the applicant stated that the HPCI system (73) was drained and laid up dry per 1-GOI-100-13.A and 0-TI-373. The core spray system (75) was drained and laid up dry per 1-GOI-100-13.17 and 0-TI-373. The air/gas environments for these systems were maintained to less than 60 percent humidity with dehumidifiers. The applicant stated that both the normal and layup environments were relatively dry (no pooling) air/gas environments. In addition, the heating and ventilation in the reactor building was maintained during layup; therefore, the inside air environment for systems 73 and 75 did not significantly change systems 73 and 75. Based on the above, the staff concluded that the layup air environments for the above components are not any more aggressive than their counterparts in the plant operating environments, and the aging effects for these components in the normal operating and layup environments are the same. RAI 3.2-1 LP is, therefore, resolved.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the HPCI system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 HPCI system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 1 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the HPCI system.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

As stated in Table 1 of the February 19, 2004, submittal, for the HPCI system (73) and core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) environments are subject to general corrosion during the period of extended outage. For the LRA AMR, the same aging effect is identified for the same components in an air/gas (internal) environment, with the One-Time Inspection Program credited as the only AMP for managing the identified aging effects. No additional AMPs were proposed for the layup program.

In RAI 3.2-2 LP, the staff requested the applicant to provide justification that additional inspection programs were not required for possible unintended moisture conditions accumulated in the above components of both the HPCI system (73) and the core spray system (75), during the period of extended outage. By letter dated October 8, 2004, the applicant stated that pooled water is not anticipated for the portions of Systems 73 and 75 addressed in Table 1 per the layup program 0-TI-373. To ensure detection of possible material degradation, the applicant stated that the restart inspection will be performed prior to the Unit 1 restart instead of at the end of the current licensing period to verify that the layup program has been adequate in protecting the material from significant degradation. Based on the lack of aggressive environments associated with the components in Systems 73 and 75, the staff found that the applicant's initiative in performing restart inspections for possible material degradation prior to Unit 1 restart is acceptable. RAI 3.2-2 LP is, therefore, resolved.

To ensure the general acceptability of the One-Time Inspection Program in managing loss of material due to general corrosion, the staff requested in RAI 3.0-2 LP that the applicant provide detailed information of the One-Time Inspection Program, and provide justification that it is adequate for managing the aging effects for the components within the dry layup systems. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.0.3.3.5.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff found that the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 HPCI system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 HPCI system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.1.2 Core Spray System

Technical Staff Evaluation. The technical staff reviewed the AMR of the core spray system (75) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The core spray system is described in LRA Section 2.3.2.5. LRA Table 3.2.2.5 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 core spray system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 1 of the applicant's February 19, 2004, submittal provides the AMR of the core spray system components within the scope of license renewal and maintained in dry layup conditions. The component types include bolting, fittings, piping, pumps, restricting orifices, strainers, tanks, tubing, and valves.

The February 19, 2004, submittal describes the internal environment of the system as being maintained at less than 60 percent RH de-humidified air. The external environment was inside air.

For the Unit 1 core spray system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel, and cast iron and cast iron alloy. Components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. No aging effects are identified for stainless steel, aluminum alloy, and polymer components in air/gas (internal) or inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 1 of the February 19, 2004, submittal for the core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel, as well as cast iron and cast iron alloy, components in air/gas (internal) or inside air (external) environments are subject to general corrosion during the period of extended outage. In the LRA AMR, the same aging effect is also identified for the same components in air/gas (internal) and inside air (external) environments. Because of the uncertainty of the dryness of air environments, the staff requested, in RAI 3.2-1 LP, that the applicant assure that the layup air environments for these components are not any more aggressive than their counterparts in the plant operating environments, and that no additional aging effects would need to be considered. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.1.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the core spray system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 core spray system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 1 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the core spray system.

- One-Time Inspection Program (B.2.1.29).
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

As stated in Table 1 of the February 19, 2004, submittal, for the core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) environments are subject to general corrosion during the period of extended outage. For the LRA AMR, the same aging effect is identified for the same components in an air/gas (internal) environment, with the One-Time Inspection Program credited as the only AMP for the material/environment combination. No additional AMPs were proposed for the counterpart components included in the layup program. In RAI 3.2-2 LP, the staff requested the applicant to provide justification that additional inspection programs were not required, for possible unintended moisture conditions accumulated in the system components during the period of extended outage. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.1.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 core spray system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 core spray system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.2 Engineered Safety Features Systems in Various Wet Environments

3.7.3.2.1 Containment System

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment system (64) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment system is described in LRA Section 2.3.2.1. LRA Table 3.2.2.1 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that the portions of Unit 1 containment system within the scope of BFN license renewal were not incorporated into the BFN layup program, but were included in the evaluation. The components within the scope of BFN license renewal for the containment system (64) saw treated (torus) water based on the locations or leakage of valves were maintained by the Chemistry Program (CI-13.1) for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 3 of the applicant's February 19, 2004, submittal provides the AMR of the containment system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, duckwork, heat exchangers, fire dampers, flexible connectors, fittings, piping, strainers, traps, tubing, and valves.

The February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air, outside air, buried, and treated water.

For the Unit 1 containment system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion. Carbon and low-alloy steel components in buried (external) environments are subject to loss of material due to general, crevice, and pitting corrosion, and MIC. Stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Elastomer components in inside air (external) and outside air (external) environments are subject to hardening and loss of strength due to elastomer degradation (ultraviolet radiation).

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates components in the containment system (64), HPCI system (73), and core spray system (75) that are exposed to an air/gas (internal) environment during normal operation, whereas their counterpart environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of these systems may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in these systems, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. By letter dated October 8, 2004, the applicant stated that Table 3 addresses the aging management for portions of several systems (including containment, HPCI, and core spray systems) laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double isolation valves was considered the same (i.e., raw or treated water) as was water flowing through the valves prior to closure. The applicant stated that the N/A denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time (restart) inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The staff determined that the applicant had adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the treated-water environment in the above three ESF systems would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform a restart inspection prior to Unit 1 restart to verify the material condition of the system components. This is acceptable to the staff; therefore, RAI 3.0-5 LP is closed for Systems 64, 73, and 75.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29).
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the containment (64), HPCI (73), and core spray (75) systems were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for these layup systems, other than those AMPs specified in LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing the results of any water sampling performed, and discuss whether the systems were stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. By letter dated October 8, 2004, the applicant stated that the torus and torus attached piping for the containment system (i.e., the torus itself) and HPCI and core spray systems (torus attached piping) saw torus water maintained by CI-13.1 chemistry program, Appendix A, Table 20, for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not flowing in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit cannot be considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. The applicant stated that torus coating touch-up/repair is part of the restart work to be completed while the torus is drained.

The applicant stated that the torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. µS/cm, 75 ppb, and 75 ppb, respectively, which are within the chemistry specifications. Sampling is performed quarterly. The applicant also stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

Based on the above information, pending the staff's acceptance of the applicant's wet layup program chemistry controls provided in SER Section 3.7.1.1, the staff determined that the applicant had adequately addressed the staff's concerns related to water chemistry existing during layup and pre-startup inspections, for the containment, HPCI, and core spray systems. RAI 3.0-6 LP is, therefore, closed for these three systems.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.2.2 High Pressure Coolant Injection System

Technical Staff Evaluation. The technical staff reviewed the AMR of the HPCI system (73) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The HPCI system is described in LRA Section 2.3.2.3. LRA Table 3.2.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that the Unit 1 HPCI system within the scope of license renewal was not incorporated into the layup program but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the HPCI system (73) saw treated (torus) water maintained by CI-13.1 chemistry program for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 3 of the applicant's February 19, 2004, submittal provides the AMR of the HPCI system components within the scope of license renewal that were not incorporated into the wet layup program. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifices, strainers, tanks, traps, tubing, turbines, and valves.

The LRA and the February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air and treated water.

For the Unit 1 HPCI system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in treated water (internal) are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Copper-alloy components in treated water (internal) are subject to loss of material due to selective leaching, crevice and pitting corrosion, as well as galvanic corrosion. Cast iron and cast iron alloy components in treated water (internal) environments are subject to a loss of material due to general, crevice, pitting, and selective leaching corrosion. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion. Elastomer components in inside air (external) environments are subject to elastomer degradation due to ultraviolet radiation.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of the applicant's February 19, 2004, submittal, components in the HPCI system (73) are shown to be exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the HPCI system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 HPCI system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.
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Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the HPCI system.

- ASME Section XI Subsections IWB, IWC, & IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29).
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.5, 3.0.3.2.9, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that the HPCI system was not formally incorporated into the Unit 1 wet layup program. This system was exposed to treated (non-controlled) water during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing results of any water sampling performed and to discuss whether the system was stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 HPCI system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 HPCI system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.2.3 Core Spray System

<u>Technical Staff Evaluation</u>. The technical staff reviewed the AMR of the core spray system (75) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The core spray system is described in LRA Section 2.3.2.5. LRA Table 3.2.2.5 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that, Unit 1 core spray system within the scope of license renewal was not incorporated into the layup program, but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the core spray system (75) saw treated (torus) water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

<u>Aging Effects</u>. Table 3 of the February 19, 2004, submittal provides the AMR of the core spray system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifice, strainers, tanks, traps, tubing, turbines, and valves.

The LRA and the February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air and treated water.

For the Unit 1 core spray system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in treated water (internal and external) are subject to loss of material due to crevice and pitting corrosion. Aluminum alloy components in treated water (internal) are subject to loss of material due to crevice and pitting corrosion, as well as crack initiation/growth due to stress corrosion cracking. Cast iron and cast iron alloy components in treated water (internal) environments are subject to a loss of material due to general, crevice, pitting, and selective leaching corrosion. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of the applicant's February 19, 2004, submittal, components in the core spray system (75) are shown to be exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation of treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the core spray system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 core spray system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the core spray system.

- ASME Section XI Subsections IWB, IWC, & IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29).
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that the core spray system was not formally incorporated into the Unit 1 wet layup program. This system was exposed to treated (non-controlled) water during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing results of any water sampling performed, and discuss whether the system was stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 core spray system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 core spray system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.3 Engineered Safety Features Systems in Various Dry Environments

3.7.3.3.1 Containment Inerting System

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment inerting system (76) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment inerting system is described in LRA Section 2.3.2.6. LRA Table 3.2.2.6 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the Unit 1 containment inerting system was not formally incorporated into the BFN layup program, but was included in the evaluation. The applicant stated that there were no moisture controls for the portions of the Unit 1 containment inerting system within the scope of BFN license renewal. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the containment inerting system components within the scope of license renewal which were not incorporated into the BFN layup program. The component types include bolting, flexible connectors, heat exchangers, fittings, piping, pumps, strainers, traps, tubing, and valves.

The applicant's February 19, 2004, submittal identified air/gas as the internal environment of the system, whereas the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 containment inerting system components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects in addition to those requiring management during the period of extended operation were identified: carbon and low-alloy steel components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Copper-alloy components in air/gas (internal) environments are subject to loss of material due to selective leaching, crevice corrosion, pitting corrosion, and galvanic corrosion. Aluminum alloy components in air/gas environments are subject to loss of material due to crevice, pitting, and galvanic corrosion, and crack initiation/growth due to SCC. Cast iron and cast iron alloy components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion, as well as selective leaching. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment inerting system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment inerting system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment inerting system.

- One-Time Inspection Program (B.2.1.29).
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the containment inerting system (76), the applicant stated that inspections will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended outage. These additional aging effects include those identified for carbon and low-alloy steel, stainless steel, nickel alloy, copper alloy, aluminum alloy, and cast iron and cast iron alloy components in system locations where condensation could build up. No descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA, Appendix B, Section B.2.1.29. This is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation. The staff found the applicant's commitment of performing one-time inspections to be acceptable, and RAI 3.0-7 LP is closed for the containment inerting system. The staff's discussion of the adequacy of the One-Time Inspection Program in managing the identified aging effects for the system components, versus periodic inspections, is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment inerting system components not incorporated in the dry layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment inerting system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.3.3.2 Containment Atmosphere Dilution System.

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment atmosphere dilution system (ADS) (84) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment ADS is described in LRA Section 2.3.2.7. LRA Table 3.2.2.7 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the Unit 1 containment ADS was not formally incorporated into the dry layup program, but was included in the evaluation. The applicant stated that there were no moisture controls for the portions of the Unit 1 containment ADS within the scope of license renewal.

The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the containment ADS components within the scope of license renewal which were not incorporated into the BFN dry layup program. The component types include bolting, fittings, flex hose, heat exchangers, piping, tanks, tubing, and valves.

The LRA and the February 19, 2004, submittal identified air/gas as the internal environment of the system, whereas the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 containment ADS components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects in addition to those requiring management during the period of extended operation were identified: carbon and low-alloy steel components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Stainless steel components in buried (external) environments are subject to loss of material due to crevice and pitting corrosion, and MIC. Copper alloy components in air/gas (internal) environments are subject to loss of material due to selective leaching, crevice corrosion, pitting corrosion, and galvanic corrosion. Aluminum alloy components in air/gas environments are subject to loss of material due to crevice, pitting, and galvanic corrosion, and crack initiation/growth due to SCC. Cast iron and cast iron alloy components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion, as well as selective leaching. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment ADS during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment ADS during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment atmosphere dilution system.

- One-Time Inspection Program (B.2.1.29).
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the containment ADS (84), the applicant stated that inspections will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended outage. These additional aging effects include those identified for carbon and low-alloy steel, stainless steel, copper alloy, aluminum alloy, and cast iron and cast iron alloy components in system locations where condensation could build up. No descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.3.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment ADS components not incorporated in the dry layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment ADS components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4 Auxiliary Systems

3.7.4.1 Auxiliary Systems in Dry Layup

3.7.4.1.1 Standby Liquid Control System

Technical Staff Evaluation. The technical staff reviewed the AMR of the standby liquid control system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The standby liquid control system is described in LRA Section 2.3.3.18. LRA Table 3.3.2.18 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 standby liquid control system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal of additional information describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-8 LP, and 3.0-10 LP are related to the standby liquid control system. These RAIs, the applicant's responses, and the staff's review of the applicant's responses are discussed in SER Section 3.7.1.3. There are no system-specific RAIs on the standby liquid control system.

Aging Effects. LRA Table 3.3.2.18 provides the AMR of the standby liquid control system components within the scope of license renewal and subject to AMR. The component types include piping, fittings, bolting, pumps, tanks, and valves.

The LRA and the February 19, 2004, submittal of additional information describe the environment during the Unit 1 shutdown as follows: the internal environment was maintained at less of 60 percent relative humidity (de-humidified air) and the external environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the Unit 1 Layup and Preservation Program Table 1, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air/gas and inside air are subject to a loss of material due to general corrosion. Stainless steel, aluminum alloy and polymer-delrin exposed to air/gas and inside air experience no aging effects.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the standby liquid control system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 standby liquid control system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the Unit Layup and Preservation Program Table 1 identifies the following AMPs for managing the aging effects described above for the standby liquid control system in dry layup.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.7 and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 standby liquid control system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 standby liquid control system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4.1.2 Off-Gas System

Technical Staff Evaluation. The technical staff reviewed the AMR of the off-gas system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The off-gas system is described in LRA Section 2.3.3.19. LRA Table 3.3.2.19 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 off-gas system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal of additional information describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-8 LP, and 3.0-10 LP are related to the off-gas system. These RAIs, the applicant's response and the staff's review of the applicant's response are discussed in SER Section. There are no system-specific RAIs on the off-gas system.

Aging Effects. LRA Table 3.3.2.19 provides the AMR of the off-gas system components within the scope of license renewal and subject to AMR. The component types include bolting, ductwork, piping and fittings.

The LRA and the February 19, 2004, submittal of additional information describe the environment during the Unit 1 shutdown as follows: the internal environment was maintained at less than 60 percent relative humidity (de-humidified air), and the outside environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the Unit 1 Layup and Preservation Program Table 1, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air/gas and inside air are subject to a loss of material due to general corrosion. Stainless steel and copper alloy exposed to air/gas and inside air experience no aging effects.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the off-gas system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 off-gas system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 1 identifies the following AMPs for managing the aging effects described above for the off-gas system in dry layup.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.7 and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 off-gas system. components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 off-gas system. components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4.1.3 Reactor Core Isolation Cooling System

Technical Staff Evaluation. The technical staff reviewed the AMR of the RCIC system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The reactor core isolation cooling system is described in LRA Section 2.3.3.23. LRA Table 3.3.2.23 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 reactor core isolation cooling system for wet layup was not formally incorporated into the wet layup program, but was evaluated. The applicant's February 19, 2004, submittal of additional information (including Table 1 and 3). shows that the RCIC system was subject to both a dry layup condition and a wetted condition. The applicant's response to RAI 3.0-6 LP shows that the RCIC torus attached piping saw torus water maintained by Chemistry Program CI-13.1 for extended periods of time. The BFN layup program for dry layup maintained the internal environment of Unit 1 reactor core isolation cooling system at less than 60 percent RH de-humidified air. The applicant's February 19, 2004, submittal of additional information (including Table 1 and 3), describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-3 LP, 3.0-4 LP, 3.0-5 LP, 3.0-6 LP, 3.0-8 LP, 3.0-9 LP and 3.0-10 LP are related to the reactor core isolation cooling system. RAIs 3.0-2 LP to RAI 3.0-8

LP are discussed in SER Section 3.7.1.3, RAI 3.0-9 LP is discussed in SER Section 3.7.1.2 and RAI 3.0-10 LP is discussed in SER Section 3.7.1.3. There are no system-specific RAIs on the reactor core isolation cooling system.

Aging Effects. LRA Table 3.3.2.23 provides the AMR of the reactor core isolation cooling system components within the scope of license renewal and subject to AMR. The component types include bolting, condenser, expansion joint, fittings, fittings - RCPB, flexible connector, heat exchangers, piping, piping - RCPB, pumps, restricting orifice, restricting orifice - RCPB, strainers, tanks, traps, tubing, turbines, valves, and valves - RCPB.

Table 1 of the February 19, 2004, submittal of additional information describes the dry layup environment during the Unit 1 shutdown as follows: the internal environment was air/gas (less than 60 percent RH) and the external environment was inside air. Table 3 of the February 19, 2004, submittal identifies the internal environment as treated water and the external environment as inside air or treated water.

For the Unit 1 system components, the applicant identified on Evaluation of the BFN Unit 1 Layup and Preservation Program Tables 1 and 3, the following materials, environments, and AERMs: carbon and low-alloy steel components as well as cast iron and cast iron alloy components. exposed to air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion; carbon and low-alloy steel components as well as cast iron and cast iron alloy components exposed to treated water are subject to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel components in treated water are subject to crevice corrosion, and pitting corrosion; copper-alloy components in treated water are subject to a loss of material due to selective leaching, crevice corrosion, galvanic corrosion, and pitting corrosion; aluminum alloy components. in treated water are subject to a loss of material due to crack initiation and growth due to SCC, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel, copper alloy, aluminum alloy, and glass components exposed to air/gas (internal) or inside air (external) environments experience no aging effects. Glass components in treated-water environment also experience no aging effects.

In response to general RAI 3.0-9 LP, the applicant identified that the RCIC steam trap drain was replaced with 2-¼ percent chromium materials to prevent FAC.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18, and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the reactor core isolation cooling system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 reactor core isolation cooling system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Tables 1 and 3 identify the following AMPs for managing the aging effects described above for the reactor core isolation cooling system in a dry layup or a treated-water environment.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.3, 3.0.3.2.5, 3.0.3.2.2, 3.0.3.2.9, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively.

In follow-up RAI 3.3-2, the staff questioned if one-time inspections are appropriate where there may be insufficient operating experience. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, October 8, 2004, and January 31, 2005, the staff found that the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 RCIC system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 reactor core isolation cooling system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4.2 Auxiliary Systems in Wet Lay up

3.7.4.2.1 Reactor Water Cleanup System

Technical Staff Evaluation. The technical staff reviewed the AMR of the reactor water cleanup system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The reactor water cleanup system is described in LRA Section 2.3.3.21. LRA Table 3.3.2.21 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 reactor water cleanup system was maintained in wet lay up during the extended shutdown. The applicant's February 19, 2004, submittal of additional information, describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs applicable to the RWCU system include RAI 3.0-1 LP, 3,0-3 LP, 3.0-5 LP, 3.0-7 LP, 3.0-8 LP, 3.0-9 LP, 3.0-10 LP, 3.0-11 LP. The description of these general RAIs, the applicant's response to these RAIs and the staff's review of the applicant's responses are included in SER Sections 3.7.1.1, 3.7.1.4, 3.7.1.3, 3.7.1.2, and 3.7.1.5. There are no system-specific RAIs for the reactor water cleanup system.

Aging Effects. LRA Table 3.3.2.21 provides the AMR of the reactor water cleanup system components within the scope of license renewal and subject to AMR. The component types include piping and fittings, heat exchangers, pumps, restricting orifices, strainers, tanks, tubing, and valves.

The LRA and the February 19, 2004, submittal of additional information, describe the environment during the Unit 1 shutdown as follows: the internal environment was flowing, air-saturated, demineralized water (treated water) and the outside environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the BFN Unit 1 Layup and Preservation Program Table 2, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to treated water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel components in treated water are subject to a loss of material due to crevice and pitting corrosion; cast iron and cast iron alloy components in treated water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion as well as selective leaching; copper and copper-alloy components in a treated-water environment are subject to a loss of material due to crevice corrosion, pitting corrosion and selective leaching. Glass components in a treated-water environment experience no aging effects; carbon and low-alloy steel components as well as cast iron and cast iron alloy components in inside air are subject to a loss of material due to general corrosion; stainless steel, copper alloy, and glass exposed to inside air experience no aging effects.

Table 2 does not identify IGSCC for the stainless steel RWCU system components during layup and LRA Section F.13 indicates that RWCU piping outside the primary containment isolation valves will be replaced with IGSCC-resistant material. In response to general RAI 3.0-9 LP the applicant submitted system-specific information in regard to specific components that will be replaced prior to startup. By letter dated January 31,2005, the applicant clarified the scope and basis for the following RWCU specific components being replaced with IGSCC-resistant material prior to Unit 1 restart:

- RWCU hot piping both inside and outside the drywell is being replaced with 316NG
- RWCU valves replaced with 316L
- RWCU pumps (IGSCC related)
- RWCU regenerative heat exchangers with 316L

Therefore, based on the commitment that stainless steel piping will be replaced with IGSCC-resistant material prior to Unit 1 restart, the staff concluded that IGSCC is not a technical concern for the RWCU system as a result of layup conditions during the extended shutdown.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the reactor water cleanup system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 reactor water cleanup system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 2 identified the following AMPs for managing the aging effects described above for the reactor water cleanup system in wet layup.

- ASME Section XI Subsections IWB, IWC and IWD Inspection Program (B.2.1.4)
- Bolting Integrity Program (B.2.1.16)
- BWR Reactor Water Cleanup System Program (B.2.1.22)
- Chemistry Control Program (B.2.1.5)
- Closed-Cycle Cooling Water System Program (B.2.1.18)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.1.3, 3.0.3.2.10, 3.0.3.2.15, 3.0.3.2.2 3.0.3.2.12, 3.0.3.1.7, 3.0.3.1.8X, and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, October 8, 2004, and January 31, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 reactor water cleanup system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 reactor water cleanup system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4.2.2 Control Rod Drive System

Technical Staff Evaluation. The technical staff reviewed the AMR of the CRD system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The CRD system is described in LRA Section 2.3.3.29. LRA Table 3.3.2.29 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 CRD system was maintained in wet layup during the extended shutdown. The applicant's February 19, 2004, submittal (including Table 2) describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-1 LP, 3.0-3 LP, 3.0-5 LP, 3.0-6 LP, 3.0-9 LP, and 3.0-10 LP are related to the CRD system. The description of the general RAIs that relates to both the SSCs in the auxiliary system and other mechanical system groups, the applicant's response to these RAIs and the staff's review of the applicant's responses are in SER Sections 3.7.1.1, 3.7.1.4, 3.7.1.3, and 3.7.1.2. System-specific RAI 3.3-2 LP on the CRD system, the applicant's responses and the staff's review of the applicant's responses are described below.

Aging Effects. LRA Table 3.3.2.29 provides the AMR of the CRD system components within the scope of license renewal and subject to AMR. The component types include bolting, fittings, fittings - RCPB, heat exchangers, piping, piping - RCPB, pumps, restricting orifice, rupture disk, strainers, strainers - RCPB, tanks, tubing, valves, and valves - RCPB.

Table 2 of the February 19, 2004, submittal describes the environment during the Unit 1 shutdown as follows: the internal environment was flowing, air-saturated, demineralized water (treated water) and the outside environment was inside air.

For the Unit 1 system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air-saturated demineralized water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel and aluminum alloy components in treated water are subject to a loss of material due to crevice and pitting corrosion; carbon and low-alloy steel components as well as cast iron and cast iron alloy components in inside air are subject to a loss of material due to general corrosion; stainless steel, copper alloy, and aluminum alloy components exposed to inside air experience no aging effects.

In RAI 3.3-2 LP the staff requested the following additional information on Table 2 concerning the internal environment and inspections for the CRD system.

LRA Table 3.3.2.29 and Table 2 of the supplement state that many carbon and low-alloy steel components in the CRD system have an internal environment of raw water during normal operation. However, Table 2 states that this environment is not applicable during the extended outage. The applicant was requested to clarify the environment during the extended outage, and discuss the implications of the environment on the aging of these components. The applicant was requested to specify any applicable aging effects with the corresponding AMPs and also discuss whether any inspections are planned to determine the extent of aging during the extended outage.

The applicant responded to RAI 3.3-2 LP (b)1 by stating that the raw cooling water system provides cooling water to the CRD pump oil cooler and thrust bearing. The applicant further clarified that the following materials see the raw water environment during layup: carbon steel piping and fittings, copper valves, copper heat exchanger (cooler) tubing, cast iron heat exchanger (cooler) head.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18, and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the CRD system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the unit CRD system during the extended shutdown.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 3 identifies the following AMPs for managing the aging effects described above for the CRD system in wet layup:

- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)
- Open-Cycle Cooling Water System Program (B.2.1.17)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.2.5, 3.0.3.2.2, 3.0.3.1.7, 3.0.3.2.11, 3.0.3.1.8, and 3.0.3.3.1, respectively.

In response to RAI 3.3-2 LP, the applicant stated that a sample of components with a raw water environment within the CRD system (85) will be inspected for the following aging effects by the One-Time Inspection Program.

- Carbon and low-alloy steel – Loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, microbiologically influenced corrosion, and biofouling
- Copper and copper alloys – Loss of material due to crevice corrosion, pitting corrosion, microbiologically influenced corrosion, biofouling, and selective leaching
- Cast iron and cast iron alloys - Loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, microbiologically influenced corrosion, biofouling, and selective leaching

The staff reviewed the applicant's above response to the RAI and determined that additional information was required. In follow-up RAI 3.3-2 LP the applicant was requested to clarify whether one-time inspection is appropriate to manage aging of carbon steel, cast iron and copper-based components in a raw water environment during layup.

The applicant's response to follow-up RAI 3.3-2 LP stated that there is no need to perform a one-time inspection on the components that were subjected to a raw water environment during layup. The applicant indicated that the inspections would have been better characterized as "restart inspection" instead of "One-Time Inspection." The applicant further stated that once the CRD system is returned to service the components will have the same AMPs applied to them as their current Unit 2 and 3 counterpart components.

Staff reviewed the applicant's response and concurred that, in general, restart inspections are appropriate to detect and correct degradation experienced during layup. However, staff is concerned that one-time inspections performed during the extended outage may not be appropriate to detect latent aging effects in the CRD system resulting from layup during the extended operating period. Latent aging effects are anticipated in crevices and in stagnant areas where contaminants are concentrated. For areas subject to concentration of contaminants during layup, the applicant should justify the application of one-time inspections in lieu of periodic inspections. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 CRD system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects [pending resolution of the general RAIs] for the Unit 1 CRD system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.4.3 Auxiliary Systems Not in Layup Program

During its review of auxiliary systems, the staff determined that additional information was needed to complete its review. By letter dated August 23, 2004, the staff issued general RAI 3.3-1 LP requesting the following additional information on systems and portions of systems that were not included in the layup program.

> LRA Section 3.0.1 describes the criteria for evaluating systems for aging during the extended outage. Systems that remain in operation for Unit 1 or in support of operation for Units 2 and 3 are not evaluated. However, based on the system descriptions, it appears that at least a portion of the following systems should have been evaluated (i.e., it appears that the system was idle or that only the main headers were needed to support operation of Units 2 and 3). Discuss the operation of the following systems during the extended shutdown, and explain why these systems were not evaluated for aging during the extended shutdown.
>
> - Residual Heat Removal Service Water System (023)
> - Control Air System (032)
> - Sampling and Water Quality System (043)
> - Emergency Equipment Cooling Water System (067)
> - Reactor Water Cleanup System (069)
> - Reactor Building Closed Cooling Water System (070)

- Radioactive Waste Treatment System (077)
- Neutron Monitoring System (092)

If it is determined that these systems, or portions thereof, met the criteria for evaluation, provide an evaluation of aging during the extended outage. Include a description of the environment, identification of AERMs, and proposed aging management. Also, discuss any inspections that are planned to determine the extent of aging during the extended outage.

By letter dated October 8, 2004, the applicant responded to RAI 3.3-1 LP by providing the following additional information.

With regard to residual heat removal service water system (23) and emergency equipment cooling water system (67), the applicant stated that the Unit 1 portions of piping and components for these systems not required for Unit 2 and 3 operation are not in the layup program. The piping and components in these systems are in shared systems and contained either raw water or moist air during the extended outage period. The applicant stated that these systems have been evaluated for a raw water and/or moist air environment for the in-service portions of these systems. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The applicant also stated that for control air system (32) the Unit 1 piping components of this system not required for Unit 2 and 3 operation but in scope for license renewal is not in the layup program. For this system, any additional aging effects would be due to moisture collecting in the system components. For the operating condition the internal environment is air/gas without a significant amount of moisture present. During layup there were no moisture controls on the non-operating Unit 1 portions of this system. Without moisture controls the possibility of moisture collecting at system low points exists. The aging effects associated with moist air are contained in the detailed layup evaluation of the containment inerting system (76) and the containment atmosphere dilution system (84). The potential aging effects for the control air will be similar to those identified for the containment inerting and containment atmosphere dilution systems. The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

For the sampling and water quality system (43), the applicant stated that the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the lay-up program. The piping and components in this system contained treated water, raw water, and/or moist air during the extended outage period. This system has been evaluated for these environments for the operating condition. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The restart inspection will be performed prior to Unit 1 restart to verify the material condition. Related to the reactor water cleanup system (69), the applicant stated that the system was evaluated per BFN Unit 1, Layup and Preservation Program, Table 2.

For the reactor building closed cooling water system (70) the applicant stated that portions of the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the layup program. The piping and components in this system contained treated water maintained to CI-13.1 and/or moist air during the extended outage period. The aging effects associated with treated water maintained to CI-13.1 are contained in the detailed layup evaluation of the reactor core isolation cooling system (71), the HPCI system (73), and the core spray system (75). The potential aging effects for the closed cooling water system (70) will be similar to those identified for the reactor core isolation cooling system (71), the HPCI system (73), and the core spray system (75). The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

For the radioactive waste treatment system (77), the applicant stated that the Unit 1 piping and components for this system are not in the layup program. The piping and components in this system within the LRA scope remained in-service. An aging effects evaluation was performed for this system and documented in LRA Table 3.3.2.25.

Finally, related to the neutron monitoring system (92), the applicant stated that the Unit 1 portions of piping and components for this system are not in the layup program. The portion of this system that is within the scope of license renewal is part of the reactor vessel pressure boundary. An aging effects evaluation was performed for the Unit 1 layup portions of the RVI system. The aging effects evaluation for the RV and RVI encompasses the neutron monitoring system (92). The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

With the staff issue raised in RAI 3.0-3 LP concerning MIC in stagnant areas, the staff reviewed the applicant's response to RAI 3.0-3 and, in general, found it to be reasonable and acceptable because it clarified that the subject systems were either in-service or were not part of the layup program. Systems that were in service during the extended outage are reviewed as part of the AMR. For systems that were not part of the layup program, the applicant includes an evaluation of aging effects and credits restart inspections to verify the material condition. In these systems, the applicant's evaluation of aging effects determined that aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The staff's evaluation of restart inspections to manage aging effects including MIC for stagnant systems not in-service can be found in SER Sections 3.0.3.3.5, 3.7.1.3, and 3.7.1.4.

3.7.5 Steam and Power Conversion Systems

3.7.5.1 Steam and Power Conversion Systems in Wet Layup

3.7.5.1.1 Feedwater System

<u>Technical Staff Evaluation</u>. The technical staff reviewed the AMR of the feedwater system (03) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The feedwater system is described in LRA Section 2.3.4.3. LRA Table 3.4.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 feedwater system was maintained in wet layup during the extended shutdown. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 2 of the applicant's February 19, 2004, submittal provides the AMR of the feedwater system components within the scope of license renewal that were maintained in wet layup conditions. The component types include bolting, fittings, piping, restricting orifices, tubing, and valves.

The February 19, 2004, submittal states that portions of the Unit 1 feedwater system are within the boundary of the layup program. However, the portions of the Unit 1 feedwater system within the scope of license renewal sees the same water as the portions of Unit 1 reactor vessel and internals system, boiler drains and vents system, recirculation system, reactor water cleanup system, and CRD system. The applicant stated that BFN maintains the internal environment of these systems with flowing, air-saturated, demineralized water per the CI-13.1 chemistry program. Due to drainage and system isolation, portions of these systems did not see the same environment as that seen by the portions of the Unit 1 feedwater system within the scope of license renewal, for an extended period of time. The applicant stated, however, that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems.

For the Unit 1 feedwater system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion; copper-alloy components in air/gas (internal) moist environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as selective leaching; no AERMS were identified for stainless steel and copper-alloy components in inside air (external) environments.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the feedwater system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 feedwater system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 2 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the feedwater system.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.9, and 3.0.3.1.7, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 2 of the February 19, 2004, submittal, for the feedwater system (03), the applicant indicated that carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion, because the components' surface temperature is less than 212°F during the period of extended outage. The applicant indicated that the components will be inspected for external corrosion prior to Unit 1 restart, without providing details for the inspection provided. The applicant also indicated that inspections will be performed prior to Unit 1 restart for the copper-alloy components for which additional aging effects (i.e., loss of material due to crevice, galvanic, and pitting corrosion, and selective leaching) were identified for the extended outage. These additional aging effects are the results of the presence of moist air in system locations where condensation could build up. The applicant indicated that inspections will be performed for the components prior to Unit 1 restart, but again, provided no descriptions of the inspections.

In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that external surface monitoring will be performed for the affected carbon and low-alloy steel components in accordance with the Systems Monitoring Program described in LRA, Appendix B, LRA Section B.2.1.39. The applicant noted that this is the same AMP proposed for managing external loss of material during the period of extended operation. By letters dated January 31 and May 18, 2005, and January 31, 2006, the applicant stated that restart inspections of the internal surface will be performed prior to Unit 1 restart to verify the material condition for the affected copper-alloy components. The applicant also committed to perform the Unit 1 Periodic Inspection Program for specific locations of piping and fitting components before and during the period of extended operation. The staff determined the Systems Monitoring Program to be adequate in managing the external aging effects. The staff also determined that the applicant's commitment of performing restart inspections, followed by periodic inspections, for the internal aging effects is acceptable. RAI 3.0-7 LP is, therefore, closed for the feedwater system. The staff's discussion of the general adequacy of restart inspections managing the aging effects versus periodic inspections during the period of extended outage is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 feedwater system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

<u>Conclusion</u>. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 feedwater system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.5.2 Steam and Power Conversion Systems in Various Wet Environments

3.7.5.2.1 Condenser Circulation Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the condenser circulation water system (27) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The condenser circulation water system is described in LRA Section 2.3.4.6. LRA Table 3.4.2.6 provides the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the portion of Unit 1 condenser circulation water system within the scope of license renewal was not incorporated into the wet layup program, but was included in the evaluation. Based, in part, on location and valve leakage, the components within the scope of license renewal for the condenser circulation water system (27) experienced raw stagnant water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the condenser circulation water system components within the scope of license renewal thath were not incorporated into the wet layup program. The component types include bolting, fittings, piping, strainers, tubing, and valves.

The February 19, 2004, submittal identified raw water as the internal environment of the system, and the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 condenser circulation water system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in raw water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC; carbon and low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion; carbon and low-alloy steel components in buried (external) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as MIC; cast iron and cast iron alloy components in raw water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC; cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion; no aging effects are identified for carbon and low-alloy steel components in embedded/encased (external) environments, and stainless steel and copper-alloy components in inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant stated that, for the condenser circulation water system (27), carbon and low-alloy steel components and cast iron and cast iron alloy components in raw water (internal) environments were susceptible to loss of material. due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC. Since the components were exposed to raw stagnant water for an extended period of time, portions of the components, especially those at low points, may have already been subject to aging degradation far more severe than their Units 2 and 3 counterparts in normal plant operation. In RAI 3.4-2 LP, the staff requested the applicant to justify the basis for not performing inspections for the aging effects prior to Unit 1 restart. By letter dated October 8, 2004, the applicant stated that during normal operation and layup, condenser circulation water system components saw raw stagnant water. Restart inspections will be performed prior to Unit 1 restart to verify the material condition. The staff determined that the applicant's commitment of performing restart inspections prior to Unit 1 restart is acceptable, and RAI 3.4-2 LP is closed. The staff's discussion of the general adequacy of the applicant's restart inspections for systems containing raw water during layup is provided in SER Section 3.7.1.

In Table 3 of its February 19, 2004, submittal, the applicant stated that, for condenser circulation water system (27), cast iron and cast iron alloy components (valves, fittings, etc.) were exposed to raw water (internal) environments, and identified no aging effects due to selective leaching. The staff noted that in raw water environments, leaching in the form of graphitic corrosion could occur with loss of iron matrix from gray cast iron. In addition, gray cast iron can also display the effects of selective leaching in relatively mild environments. In RAI 3.4-3 LP, the staff requested the applicant to discuss why selective leaching is not identified as a potential aging mechanism requiring management for the components. By letter dated October 8, 2004, the applicant stated that the aging effects write-up in its February 19, 2004, submittal did identify selective leaching as an aging mechanism for gray cast iron for the condenser circulation water system, and the line item in Table 3 should have included selective leaching for gray cast iron in the system. This response is acceptable to the staff, and RAI 3.4-3 LP is closed.

In Table 3 of the applicant's February 19, 2004, submittal, the applicant indicates that components in the condenser circulation water system (27) and gland seal water system (37) are exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of these systems saw a moist air environment for extended periods of time. The table states, however, that the evaluation for raw and treated water encompasses the aging effects for a moist air environment in these systems. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the raw and treated-water environment would encompass that of the aging effects for a moist air environment in these systems, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing raw or treated-water environment during normal operation. By letter dated October 8, 2004, the applicant stated that Table 3 addresses the aging management for portions of several systems (including condenser circulation water and gland seal water systems) laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double isolation valves was considered the same (i.e., raw or treated water) as was flowing through the valves prior to closure. The applicant stated that the N/A (not applicable) denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The staff determined that the applicant had adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the raw and treated-water environments, in the above two systems, would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform restart inspections prior to Unit 1 restart, to verify the material condition of the system components. This is acceptable to the staff, and RAI 3.0-5 LP is closed for the condenser circulation water system (27) and gland seal water system (37) systems. The staff's discussion of the general adequacy of the restart inspections for systems containing treated water and raw water during layup is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the condenser circulation water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 condenser circulation water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 identifies the following AMPs for managing the aging effects described above for the condenser circulating water system.

- One-Time Inspection Program (B.2.1.29)
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant identified no additional AMPs for the components in this layup system, other than the above AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the conclusion by discussing the water samples performed for the normal operation and the period of extended outage. By letter dated October 8, 2004, the applicant stated that the condenser circulation water system was exposed to Tennessee River water, which is the same environment it is exposed to during normal operation. Without the addition of foreign chemicals, the aging effects during normal operation and during layup are the same. However, the applicant stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition. This commitment is acceptable to the staff, and RAI 3.0-6 LP is closed for the condenser circulation water system. The staff's discussion of the general adequacy of the restart inspections as it relates to the systems containing raw water during layup is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; January 31, and May 18 and 27, 2005; the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 condenser circulation water system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condenser circulation water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.5.2.2. Gland Seal Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the gland seal water system (37) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The gland seal water system is described in LRA Section 2.3.4.7. LRA Table 3.4.2.7 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the portion of the Unit 1 gland seal water system within the scope of BFN license renewal was not incorporated into the BFN wet layup program, but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the gland seal water system (37) saw treated water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the gland seal water system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, fittings, piping, tanks, tubing, and valves.

The February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air.

For the Unit 1 gland seal water system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; copper-alloy components in treated water (internal) environments are subject to loss of material due to selective leaching, crevice and pitting corrosion; cast iron and cast iron alloy components in treated water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as selective leaching; cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion; no AERMS are identified for carbon and low-alloy steel in air/gas (internal) environments, copper alloy components in air/gas (internal) environment, and cast iron and cast iron alloy in air/gas (internal) environments no aging effects are identified for glass components in treated water (internal), air/gas (internal), and inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant stated that the portion of the gland seal water system (37) within the scope of license renewal was not incorporated into the Unit 1 wet layup program. The applicant identified various aging effects for carbon and low-alloy steel, copper alloy, and cast iron and cast iron alloy components in treated water (internal) environments. To ensure that these components have not been subjected to aging degradation more severe than their Units 2 and 3 counterparts during plant operation, in RAI 3.4-1 LP, the staff requested that the applicant (1) describe the general environments associated with the above system components; (2) provide a detailed description of the water chemistry of the treated water and discuss its differences from the water chemistry existing in the plant operation; (3) discuss any water chemistry monitoring that had been performed for the treated water during the layup period; (4) discuss the possibility of incurring more severe aging degradations to these layup components than could have occurred during plant operation, considering the potential effects of different water temperature and stagnant flow condition; (5) discuss how the latent effect of the potentially more severe aging degradation occurring in the Unit 1 layup can be accounted for in the license AMR; and (6) justify the basis for not performing inspections for potential aging effects for these components prior to Unit 1 restart. By letter dated October 8, 2004, the applicant provided the following information:

1. Gland seal water system was drained (ambient air present) with the gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system were not completely drained (the layup environment for the system is treated (condensate) water and moist air from possible pooling of treated water between drain or isolation valves and in the loop seals). Therefore, stagnant treated water supplied from the condensate system (02) was evaluated for these areas.
2. The impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. µS/cm, 75 ppb, and 75 ppb, respectively. Sampling is performed weekly. The chemistry program implemented during the wet layup period is essentially the same program that BFN uses on the two operating units during cold shutdown conditions for refueling and maintenance outage. This extended operation program would consist of CI-13.1 "Chemistry Program" controls which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515).
3. As discussed in Item (1), the treated water is sampled and monitored per the Chemistry Control Program CI-13.1. The aging effects/aging mechanisms for the components within the systems in layup are similar to those determined for the operational units.
4. As discussed in Item (1), the possibility of low flow or stagnant conditions exists in this system. Due to low flow conditions in the system, the restart inspection will be performed prior to Unit 1 restart to verify the material condition.
5. There have been no latent effects identified for the chemistry program implemented during the Unit 1 wet layup period. This program is essentially the same program that BFN uses for operating units during cold shutdown conditions for refueling and maintenance outages (EPRI BWR Water Chemistry Guidelines TR-103515-R2).
6. The restart inspection will be implemented prior to Unit 1restart.

Based on the above responses to the RAI, the staff considered that the applicant had adequately addressed its concerns, and ensured that the wet layup components in the system had not been subjected to aging degradation more severe than their Units 2 and 3 counterparts during plant operation. RAI 3.4-1 LP is, therefore, closed for the gland seal water system. The staff's discussion for the general adequacy of the One-Time Inspection Program as a verification program for layup and chemistry control is provided in SER Section 3.7.1.3.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) are exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A.” This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.5.2.1.

Table 3 of the applicant's February 19, 2004, submittal indicates that, for gland seal water system (37), copper-alloy components and cast iron and cast iron alloy components saw treated (condensate) water for an extended period of time. The applicant identified loss of material due to general corrosion, selective leaching, crevice corrosion, and pitting corrosion as the AERMs. In RAI 3.4-4 LP, the staff requested the applicant to explain why galvanic corrosion is not identified as a potential aging mechanism for the components. By letter dated October 8, 2004, the applicant stated that the cast iron components within the gland seal water system (37) are in contact with carbon steel piping. Cast iron and carbon steel are grouped together in the galvanic series as similar metals. Since cast iron components within the system are not in contact with more cathodic materials, galvanic corrosion is not a concern. Similarly, copper-alloy components are not in contact with a more cathodic material such as stainless steel within the gland seal water system. Therefore, galvanic corrosion is not a concern. The staff found the applicant's explanation to be acceptable, and RAI 3.4-4 LP is closed.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the gland seal water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 gland seal water system during the extended shutdown.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the gland seal water system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by discussing the water sampling performed for the normal operation and the period of extended outage. By letter dated October 8, 2004, the applicant stated that the system had been drained (ambient air present) with gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system had not been completely drained. Therefore, stagnant treated water supplied from the condensate system (02) was evaluated for these areas. The applicant stated that a restart inspection will be performed prior to Unit 1 restart to verify the material condition. The staff found the applicant's commitment to perform a restart inspection for the potential low points in the system to be acceptable, and RAI 3.0-6 LP is closed for the gland seal water system. The staff's discussion of the general adequacy of the restart inspections in managing the identified aging effects for the system components, as opposed to periodic inspections, is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 gland seal water system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 gland seal water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.5.3 Steam and Power Conversion Systems in Various Dry Environments

3.7.5.3.1 Main Steam System

Technical Staff Evaluation. The technical staff reviewed the AMR of the main steam system (01) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The main steam system is described in LRA Section 2.3.4.1. LRA Table 3.4.2.1 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that portions of Unit 1 main steam system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal are those that lack moisture controls and are considered moist air control components. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the main steam system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, fittings, piping, restricting orifices, strainers, tubing, and valves.

The applicant's February 19, 2004, submittal identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air.

For the Unit 1 main steam system components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects different from those requiring management during the period of extended operation were identified: aluminum alloy components in air/gas (internal) moist air environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as crack initiation/growth due to SCC, carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in air/gas (internal) moist air environments are subject to loss of material due to crevice corrosion and pitting corrosion; no aging effects are identified for aluminum alloy and stainless steel components in inside air (external) environments.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the main steam system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 main steam system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the main steam system.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.5, 3.0.3.2.9, 3.0.3.1.7, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the main steam system (01), the applicant indicated that inspections will be performed prior to Unit 1 restart for the aluminum alloy components for which additional aging effects (i.e., loss of material due to crevice, galvanic, and pitting corrosion, and crack initiation/growth due to SCC) had been identified for the extended outage. These additional aging effects are the results of the presence of moist air in system locations where condensation could build up. The applicant indicated that inspections will be performed for the components prior to Unit 1 restart. However, no descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA Section B.2.1.29. The applicant noted that this is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation. By letter dated January 31, 2005, in response to RAI 3.0-10 LP, the applicant stated that the inspections described in the October 8, 2004, letter would have been better characterized as restart inspections instead of one-time inspections. Thus, the reference to the One-Time Inspection Program performed prior to restart in the October 8, 2004, letter is considered to be a restart inspection. The staff found the applicant's commitment to perform restart inspections prior to Unit 1 restart to be acceptable, and RAI 3.0-7 LP is closed for the main steam system. The staff's discussion of the general adequacy of restart inspections managing the identified aging effects versus periodic inspections during the period of extended outage is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, May 18 and 27, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 main steam system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 main steam system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.5.3.2 Condensate and Demineralized Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the condensate and demineralized water system (02) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The condensate and demineralized water system is described in LRA Section 2.3.4.2. LRA

Table 3.4.2.2 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that portions of Unit 1 condensate and demineralized water system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal lacked moisture controls and is, therefore, considered moist air. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004 submittal; provides the AMR of the condensate and demineralized water system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, condenser, expansion joint, fittings, piping, pumps, restricting orifices, tanks, tubing, and valves. In its submittal, the applicant. identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air and outside air.

For the Unit 1 condensate and demineralized water system components, the applicant identified the following materials, environments, and AERMs: copper-alloy components in air/gas (internal) moist air environments are subject to loss of material due to selective leaching, crevice corrosion, and pitting corrosion; aluminum alloy components in air/gas (internal) moist air environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as crack initiation/growth due to SCC; carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, and pitting corrosion; carbon low-alloy steel; and cast iron and cast iron alloy components in inside air (external) or outside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in air/gas (internal) moist air environments are subject to loss of material due to crevice corrosion and pitting corrosion; cast iron and cast iron alloys in air/gas (internal) moist air environments are subject to loss of material due to galvanic, general, crevice, and pitting corrosion, as well as selective leaching; no aging effects are identified for Copper-alloy components in inside air (external) environments; no aging effects are identified for aluminum alloy, and stainless steel components in an inside air. (external) or outside air (external) environment; no aging effects are identified for polymer materials in an air/gas (internal) moist air or inside air (external) environment.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of its February 19, 2004, submittal, the applicant identified galvanic corrosion for the cast iron and cast iron alloys in air/gas (internal) environments during the Unit 1 layup period, but not for the plant operating condition. In RAI 3.4-5 LP, the staff requested the applicant to explain the discrepancy. By letter dated October 8, 2004, the applicant stated that the cast iron valves and fittings within the scope of license renewal for both normal operation and Unit 1 layup are coupled with either carbon steel or aluminum. Due to cast iron being either equal to or greater than carbon steel or aluminum in galvanic series, galvanic corrosion is not a concern for the cast iron components within the scope of license renewal for the condensate and demineralized water system. The staff found the applicant's explanation to be acceptable, and RAI 3.4-5 LP is closed.

In RAI 3.4-6 LP, the staff requested the applicant to explain why galvanic corrosion was not identified as a potential aging mechanism for the copper-alloy components in the condensate and demineralized water system that are exposed to air/gas (internal) moist air environments. By letter dated October 8, 2004, the applicant stated that the copper-alloy fittings and valves within the scope of license renewal for the condensate and demineralized water system are not in contact with a more cathodic material such as stainless steel or nickel-based alloys. Therefore, galvanic corrosion is not a concern for the components of the condensate and demineralized water system during the period of extended operation. The staff found the applicant's explanation to be acceptable, and RAI 3.4-6 LP is closed.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the condensate and demineralized water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 condensate and demineralized water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the condensate system and demineralized water system.

- Chemistry Control Program (B.2.1.5)
- Aboveground Carbon Steel Tanks Program (B.2.1.26)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.6, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the condensate and demineralized water system (02), no AMPs other than those identified above for the period of extended operation are noted for the extended outage. In RAI 3.4-5 LP, the staff requested the applicant to justify the basis for not performing inspections of the affected system components prior to Unit 1 restart. By letter dated October 8, 2004, the applicant stated that the one-time (restart) inspections described in the LRA will be performed prior to Unit 1 restart to verify the material condition. The staff found the applicant's commitment of performing these inspections prior to Unit 1 restart to be acceptable, and considers RAI 3.4-5 LP closed for this system. The staff's discussion of the general adequacy of the restart inspections managing the aging effects versus periodic inspections for the system components is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, and January 31, May 18, and 27, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 condensate and demineralized water system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condensate and demineralized water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.5.3.3 Heater Drains and Vents System

Technical Staff Evaluation. The technical staff reviewed the AMR of the heater drains and vents system (06) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The heater drains and vents system is described in LRA Section 2.3.4.4. LRA Table 3.4.2.4 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that portions of Unit 1 heater drains and vents system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal lack moisture controls and are considered moist air control components. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown 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 adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the heater drains and vents system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, fittings, piping, traps, and valves.

The applicant's February 19, 2004, submittal identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air.

For the Unit 1 heater drains and vents system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the heater drains and vents system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 heater drains and vents system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the heater drains and vents system.

- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)

SER Sections 3.0.3.2.2, 3.0.3.2.9, and 3.0.3.1.7, respectively, present the staff's detailed review of these AMPs. During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the heater drains and vents system (06), the applicant indicated that carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion, because the components' surface temperature is less than 212 °F during the period of extended outage. The applicant indicated that the components will be inspected for external corrosion prior to Unit 1 restart, but provided no details for the inspection. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that external surface monitoring the affected carbon and low-alloy steel components in accordance with the Systems Monitoring Program described in the LRA, Appendix B, Section B.2.1.39 is performed. The applicant noted that this is the same AMP proposed for managing external loss of material is performed during the period of extended operation. The staff determined the Systems Monitoring Program to be adequate in managing the external aging effects. RAI 3.0-7 LP is, therefore, closed for the heater drains and vents system (06).

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 heater drains and vents system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 heater drains and vents system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.7.6 Containments, Structures, and Component Supports

3.7.6.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant addressed the aging management of containments, structures and component supports. LRA Section 3.0.1 contains a summary of the Evaluation of the Unit 1 Layup and Preservation Program. By letter dated February 19, 2004, the applicant submitted additional information, entitled, Submittal of Evaluation of the BFN Unit Layup and Preservation Program, was reviewed by the staff. The staff determined that it needed additional information to complete its review.

3.7.6.2 Technical Staff Evaluation

The technical staff reviewed the applicant's AMR results for BFN containments, structures and component supports and reported its evaluation findings in SER Section 3.5. The staff also reviewed the containment and structural aspects of the applicant's evaluation of the BFN Unit 1 Layup and Preservation Program, and determined that additional information was needed to complete its review.

The staff determined that the BFN document titled, "Evaluation of the BFN Unit 1 LayUp and Preservation Program," including Tables 1 through 4, did not provide information related to BFN's evaluation of the Unit 1 spent fuel storage system layup effects. RAI 3.5-1 (related to Unit 1 layup issue) requested, by letter dated June 23, 2004, that the applicant describe the method adopted in assessing the Unit 1 spent fuel storage system related layup effects. The applicant was also asked to provide a discussion of the applicable spent fuel pool environments (any delta change in pool water chemistry, ambient humidity, and temperature, etc.), results of past periodic inspections of the spent fuel pool structural components and pool liners, any observed pool leakages or degraded conditions, and corrective actions taken to support BFN's conclusion that no layup effect is applicable to the Unit 1 spent fuel storage system.

By letter dated July 19, 2004, the applicant responded that:

> The Unit 1 spent fuel storage system was never placed in layup. The Unit 1 spent fuel storage system contains spent fuel and remained in service since Unit 1 was shut down and defueled in 1985. The Unit 1 spent fuel storage pool is located on elevation 664.0' of the Unit 1 reactor building. This area where the spent fuel pools are located is referred to as the refuel floor and is common for all three units (i.e., there are no physical barriers separating the spent fuel pools from the other units). Therefore the spent fuel pools are exposed to the same operating environments. The spent fuel storage pool chemistry is maintained in accordance with Technical Requirement Manual section TR 3.9.3 Spent Fuel Pool Water Chemistry.
>
> The spent fuel pool storage system is in service and complies with all applicable license and regulatory requirements. The structural components of the Unit 1 spent fuel storage

> system are being monitored under the Maintenance Rule (Structures Monitoring Program) requirements, which are the same requirements as those for inspection of the Unit 2 and 3 spent fuel storage system. Plant procedure 0-TI-346 implements the requirements of the Maintenance Rule and contains the same performance criteria for all 3 units. The Maintenance Rule inspection results for Unit 1 spent fuel storage pool are consistent with the Maintenance Rule inspection results for Unit 2 and 3 spent fuel storage pools. The structural components of the Unit 1 spent fuel pool and the supporting equipment of the spent fuel pool storage system are all exposed to an environment that is consistent with the operating environments of the Units 2 and 3 spent fuel storage system. Any degraded condition discovered during system operation or as part of the Maintenance Rule inspection of the Unit 1 spent fuel storage system is handled the same as for the Units 2 and 3 spent fuel storage systems. The BFN Corrective Action Program to address degraded conditions is SPP-3.1. The structural components of BFN spent fuel storage system are addressed in LRA Section 2.4.2.1.
>
> The operating environment for the Unit 1 spent fuel storage system is consistent with the operating environments of the Units 2 and 3 spent fuel storage systems and the system has been maintained consistent with license and regulatory requirements and the plant corrective program. Therefore, there is no difference between the Unit 1 spent fuel storage system and those of Units 2 and 3. Since the system was not in layup, as described above, no layup effects are applicable to the Unit 1 system. This is the basis for not including the spent fuel storage system to the BFN document "Evaluation of the BFN Unit 1 Layup and Preservation Program."

The staff found the applicant's response, which is based on plant-specific structural configuration and operational experience, adequate and reasonable to support its assertion that no layup effects are applicable to the Unit 1 spent fuel storage system. Therefore, the RAI is considered closed.

In RAI 3.5-2 the staff requested the applicant to describe the approach used in evaluating the Unit 1 structures and component supports related layup effects. The staff also requested the applicant to provide a discussion of the environments applicable to Unit 1 structures and component supports (e.g., any exposure to aggressive chemicals or ponding of water, significant change in ambient humidity and temperature, etc.), results of past periodic inspections of the structures and component supports, any observed degraded conditions, and corrective actions taken to support BFN's conclusion that no layup effect is applicable to Unit 1 structures and component supports that require an AMR.

In its letter dated July 19, 2004, the applicant responded that:

> For Unit 1 structures and component supports, the external service environments defined in Table 3.0.2 of the LRA were used in the aging management review. An example of an environment is the "Inside Air" environment that is defined in Table 3.0.2 as "Atmospheric air, maximum average temperature 150 °F, humidity up to 100 percent, potentially exposed to ionizing radiation, not exposed to weather." The range of interior temperatures, pressures, relative humidity, and radiation dose for the reactor building and primary containment are defined in calculations ND-Q1999-900031 (RIMS W78 030430 005), "Summary of Operational Environmental Conditions for Browns Ferry Nuclear Plant," ND-Q2999-880143 (RIMS R14 020723 105), "Summary of Harsh

Environmental Conditions for Browns Ferry Unit 2" and NDQ3999- 910035 (RIMS R14 020723 104), "Summary of Harsh Environmental Conditions for Browns Ferry Unit 3." The interior temperatures, pressures, relative humidity, and radiation dose are shown on the Harsh Environmental Data Drawings 47E225 series for each unit. The environmental conditions defined in the referenced calculations are enveloped by the definition for "Inside Air" contained in Table 3.0.2, except for the area of the main steam tunnel located on elevation 565.0' of the Units 2 and 3 reactor buildings. The main steam tunnels during plant operation have an average area temperature of 160°F. This temperature occurs as a result of plant operation and has not been seen in the same area of the Unit 1 reactor building during plant lay-up. The Unit 1 lay-up environment is the same or bounded by the evaluated operating environments.

The Unit 1 reactor building structure is subject to the Maintenance Rule SMP requirements. A baseline inspection for the BFN SMP was performed in 1997. All the same attribute inspections that were performed for Units 2 and 3 were performed for Unit 1. This inspection is documented in calculation CDQ-0303-970086 (RIMS R14 971105 102). LCEI-CI-C9, "Procedure for Walkdown of Structures for Maintenance Rule," was the procedure utilized to perform SMP inspections and requires the documentation of defects in accordance with the requirements of the procedure. There were two defects noted from the inspection of the Unit 1 reactor building, and these two defects were noted as: (1) a personnel lock door that appeared to not be airtight and (2) rust was noted on some of the torus reinforcement steel between bays 12-13, 13-14, and 14-15. These defects were dispositioned as not affecting structural function. The SMP requires a reinspection on a five-year frequency. The 2002 SMP inspection is documented in calculation CDQ-0303-2003-0260 (RIMS R14 030211 102). During the 2002 SMP inspections, there were four defects noted from the inspection of the Unit 1 reactor building and which were dispositioned as not affecting structural function. These four defects were noted as: (1) a concrete pad at the floor around conduit was chipped, (2) bolt missing from angle securing the structural plate partition wall to the concrete floor, (3) in the southwest comer of a stairwell, mortar was missing at one end of the masonry block, and (4) some concrete deterioration was noted in bay 7 of the torus area (work in progress to repair the area was noted from walkdown). These defects noted from the two inspection periods can be categorized as isolated conditions and do not represent an adverse trend that will affect the functionally of structural components.

The component supports located in Unit 1, except for those that are required for Unit 2 or Unit 3 system operation, are not subject to periodic inspections during the shutdown period. All component supports for safety-related systems required for Unit 1 operation are to be inspected and existing configurations confirmed as part of the Unit 1 recovery effort. The following plant procedures (walkdown instructions [WI]), are utilized: WI-BFN-0-CEB-01 was used for piping and supports, WI-BFN-0-CEB-02 was used for structural items, and WI-BFN-0-GEN-01 was used for both piping/supports and structural steel as a general walkdown procedure. Additionally, the following procedures were used to document baseline configurations for other component supports:

WI-BFN-0-CEB-03 - Small Bore Piping
WI-BFN-0-CEB-04 - Seismic Verification of A46 and IPEEE
WI-BFN-0-CEB-05 - Pipe Rupture/HELB
WI-BFN-0-CEB-06 - Seismically Induced Water Spray

> The inspections would document as-built configurations or existing plant configurations that did not conform to the acceptance criteria defined in the WI. These configurations would be evaluated to design criteria requirements. If the evaluations determined that the configuration did not meet the design criteria requirement, a plant modification would be designed and issued under the plant work control process.
>
> An electronic search of the site Corrective Action Program for PERs was performed to identify any adverse conditions with component supports. The search did not result in the identification of any adverse conditions.
>
> The environment for the Unit 1 structures and component supports is consistent with the operating environments of the Units 2 and 3 structures and component supports; therefore, there is no difference in the Unit 1 structures and component supports from Units 2 and 3 and no lay-up affects are applicable to Unit 1.

The staff found the above response very plant-specific and reasonably detailed to justify the applicant's assertion that the environment of the Unit 1 structures and component supports is consistent with the operating environments of the Units 2 and 3 structures and component supports; therefore, no layup effects are applicable to Unit 1 structures and component supports. RAI 3.5-2 (related to Unit 1 layup issue) is considered resolved.

In RAI 3.5-3, the staff pointed out that, when the plant is operating, the containment drywell, torus, and connecting vent assemblies are subjected to a relatively inert environment, and all the requirements related to their inspections, and leak-rate testing are applicable. These requirements ensure the leak tight and structural integrity of these components. Also, industry operating experience problems, as reflected in NRC's generic letters, information notices, and other industry published event reports are considered applicable. These activities may or may not have been considered for Unit 1 during its long layup. In this context, the applicant was requested to provide information that would describe the benchmark condition of the containment pressure boundary related components prior to Unit 1 restart, and actions that will be taken prior to the extended period of operation. The relevant regulatory requirements are 10 CFR 50,55a, and Appendix J of 10 CFR 50. The relevant generic letters are GL 87-05, GL 89-16, and GL 98-05. The relevant information notices are IN 86-99, IN 88-82, IN 89-06, IN 89-79, and IN 92-20.

In its letter dated July 19, 2004, the applicant responded that:

> For the Unit 1 containment drywell and torus, the environment during the extended outage was the same as or bounded by the evaluated operating unit environments. LRA Table 3.0.2 describes the containment environment for the drywell and torus that was used in the AMR as "Atmospheric air, maximum average temperature 150°F, humidity up to 100 percent, potentially exposed to ionizing radiation, not exposed to weather." The applicant pointed out that "Inerting was not credited for elimination of aging effects requiring aging management, and that the Unit 1 containment environment associated with temperature and ionizing radiation are not as severe as the evaluated (operating) environment conditions." The torus was subject to the torus water environment during the shutdown period. The torus was subsequently drained and is being refurbished as part of the Unit 1 recovery effort.

On the subject of containment inspections and leak-rate testing, the applicant stated that 100 percent of the examinations required in Examination Categories of Table IWE-2500-1 for the First Inspection Interval will be completed as pre-service exams before Unit 1 restarts except those that may be excluded by 10 CFR 50.55a and where specific written relief has been granted by the staff. The requirements of ASME Section XI In-Service Inspection Subsection IWE, 1992 Edition with the 1992 Addenda will be implemented on Unit 1. Type A, B, and C leak rate testing required by 10 CFR 50 Appendix J will also be performed prior to Unit 1 restart.

In addition, the applicant addressed the relevant information notices and generic letters as follows:

- NRC GL 87-05: Request Additional Information Assessment - Degradation of Mark I Drywells

The applicant provided the staff with the results of the ultrasonic testing for corrosion degradation of the drywell liner plate, RIMs No. L44 880830 801, dated August 30, 1988. The results of the ultrasonic testing state that each unit's drywell was ultrasonically tested near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. On Unit 1, no reading below the nominal thickness of one inch was measured, indicating that the integrity of the drywell liner plate was maintained.

- NRC GL 89-16: Installation of a Hardened Wet Well Vent. BFN will be installing the hardened well vent as part of the Unit 1 recovery effort. This generic letter does not address aging effects or aging management considerations.

- NRC IN 86-99: Degradation of Steel Containments. See response to GL 87-05

- NRC IN 88-82: Torus Shells with Corrosion and Degraded Coatings on BWR Containments. In 1983, Engineering Change Notice (ECN) P0555 was issued to completely inspect and recoat the torus as necessary. The Unit 1 work was completed on this ECN.

- NRC IN 89-06: Bent Anchor Bolts in Boiling Water Reactor Torus Supports. Based on the configuration of the BFN torus supports, it has been determined that BFN tie down bolts would not be subject to the effects that occurred at plant Hatch. This information notice does not address aging effects or aging management considerations.

- NRC IN 92-20: Inadequate Local Leak Rate Testing. The vent line bellows at BFN are of a different design (single-ply bellows) than the Quad Cities bellows identified in IN 92-20. The design of the BFN penetration bellows allows full pressure to be transmitted to all portions of the bellows during Appendix J testing.

In addition to the above information, the applicant addressed the staff's RAIs related to the Unit 1 primary containment during the AMR of other two units. They are discussed in SER Section 3.5.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, and a teleconference held between the staff and the applicant on

April 14, 2004, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 containment, structures, and component supports during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.7.6.3 Conclusion

On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 containment, structures, and component supports during the extended shutdown, so that there is reasonable assurance that the intended functions of these Unit 1 structural components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded 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).

3.8 Conclusion for Aging Management

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and Appendix B, "Aging Management Programs and Activities." On the basis of its review of the AMR results and AMPs, the staff concluded that the applicant had demonstrated that the aging effects 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 applicable UFSAR supplement program summaries and concluded that the UFSAR supplement adequately describes the AMPs credited for managing aging as required by 10 CFR 54.21(d).

With regard to these matters, the staff concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the BFN CLB in order to comply with 10 CFR 54.21(a)(3) are in accord with the Atomic Energy Act of 1954, as amended, and NRC regulations.

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SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 <u>Identification of Time-Limited Aging Analyses</u>

This section discusses the identification of time-limited aging analysis (TLAAs). The applicant discusses the TLAAs in license renewal application (LRA) Sections 4.2 through 4.7. Safety evaluation report (SER) Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

The TLAAs are certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to 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 its letters dated June 9, 2005, and June 15, 2005, the applicant determined that LRA Sections 4.7.2, 4.7.3, and 4.7.5 should not be considered TLAAs; therefore, they were deleted from the application (See SER Sections 4.7.2, 4.7.3, 4.7.5).

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant may provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for the Browns Ferry Nuclear Plant (BFN) against the six criteria specified in 10 CFR 54.3. The applicant indicated that it had identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable vendor reports. The applicant listed the following applicable TLAAs in LRA Table 4.1.1, “List of Time-Limited Aging Analyses”:

- neutron embrittlement of the reactor vessel and internals
- metal fatigue
- environmental qualification of electrical equipment
- loss of prestress in concrete containment tendons
- primary containment fatigue
- reactor building crane load cycles
- corrosion – flow reduction
- dose to seal rings for the high-pressure coolant injection and reactor core isolation cooling containment isolation check valves
- radiation degradation of drywell expansion gap foam

- corrosion – minimum wall thickness
- irradiation assisted stress corrosion cracking of reactor vessel internals
- stress relaxation of core plate hold-down bolts
- emergency equipment cooling water weld flaw evaluation

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it had not identified any exemptions granted under 10 CFR 50.12 that were based on a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to BFN. The staff reviewed the information to determine if the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As defined in 10 CFR 54.3, TLAAs are analyses that meet the following six criteria:

1. Involve systems, structures, and components that are 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 (40 years);
4. Are 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); and
6. Are contained or incorporated by reference in the CLB.

The applicant provided a list of common TLAAs from U.S., Nuclear Regulatory Commission Regulatory Guide (NUREG)-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” (SRP-LR) dated July 2001. The applicant listed those TLAAs that are applicable to BFN, in LRA Table 4.1.1, “List of Time-Limited Aging Analyses.”

As required by 10 CFR 54.21(c)(2), an applicant must provide a list of all the exemptions granted under 10 CFR 50.12 that are based on a TLAA and evaluated and justified for continuation through the period of extended operation. In its LRA, the applicant stated that each active exemption was reviewed to determine whether the exemption was based on a TLAA. The applicant did not identify any TLAA-based exemptions. On the basis of the information provided by the applicant with regard to the process used to identify TLAA-based exemptions, as well as the results of the applicant’s search, the staff concluded that the applicant identified no TLAA-based exemptions that are justified for continuation through the period of extended operation, in accordance with 10 CFR 54.21(c)(2).

4.1.3 Conclusion

On the basis of its review, the staff concluded that the applicant provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff also confirmed that no exemptions to 10 CFR 50.12 have been granted on the basis of a TLAA, as required by 10 CFR 54.21(c)(2).

4.2 <u>Neutron Embrittlement of Reactor Vessel and Internals</u>

During plant service, neutron irradiation reduces the fracture toughness of ferritic steel in the reactor vessel (RV) beltline region of light-water nuclear power reactors. Areas of review to ensure that the RV has adequate fracture toughness to prevent brittle failure during normal and off-normal operating conditions are (1) upper-shelf energy (USE), (2) adjusted reference temperature (ART), (3) a low-pressure coolant injection (LPCI) reflood thermal shock analysis, (4) heatup and cooldown (pressure-temperature limits) curves, (5) Boiling Water Reactor Vessel and Internals Project (BWRVIP)-05 analysis for elimination of circumferential weld inspection, and (6) analysis of the axial welds. The adequacy of the analyses for these six areas is reviewed for the period of extended operation.

The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}), and a margin term. The delta RT_{NDT} is the product of a chemistry factor (CF) and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in Regulatory Guide (RG) 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” or from surveillance data. The fluence factor is dependent upon the neutron fluence. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the CF was determined using the tables in RG 1.99, Revision 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence, and the calculation methods. Revision 2 of RG 1.99 describes the methodology to be used in calculating the margin term. The mean RT_{NDT} is the sum of the initial RT_{NDT} and the delta RT_{NDT}, without the margin term. The delta RT_{NDT} and ART calculations meet the criteria of 10 CFR 54.3(a); therefore, they are considered as TLAAs.

The ART values are used in the analysis for the adjusted reference temperature for the RV material due to neutron embrittlement, the pressure-temperature limits analysis, and the reflood thermal shock analysis. The mean RT_{NDT} values are used in the analysis of the circumferential weld examination relief and the axial weld failure probability.

Appendix G of 10 CFR Part 50 provides the staff’s criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The Rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by the American Society of Mechanical Engineers (ASME) Code Section XI, Appendix G. The Rule also mandates that the methods used to calculate USE values account for the effects of neutron irradiation on the USE values for the materials and incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50 Appendix H RV Material Surveillance Program.

RG 1.99, Revision 2, provides an expanded discussion regarding the calculation of Charpy USE values and describes two methods for determining Charpy USE values for RV beltline materials, depending on whether a given RV beltline material is represented in the plant's reactor vessel material surveillance program. If surveillance data are not available, the Charpy USE is determined in accordance with position 1.2 in RG 1.99, Revision 2. If surveillance data are available, the Charpy USE 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 the percentage drop in Charpy USE is dependent upon the amount of copper in the material and the neutron fluence. Since the analyses performed in accordance with 10 CFR Part 50 Appendix G are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4*t*), the neutron fluence used in the Charpy USE analysis is the neutron fluence at the 1/4*t* depth location.

The applicant described its evaluation of this TLAA in LRA Section 4.2, "Neutron Embrittlement of the Reactor Vessel and Internals." In order to demonstrate that neutron embrittlement does not significantly impact boiling water reactor (BWR) RV and vessel internals integrity during the license renewal term, the applicant included discussion of the following topics related to neutron embrittlement in LRA Section 4.2:

- reactor vessel materials upper-shelf energy reduction due to neutron embrittlement (LRA Section 4.2.1)
- adjusted reference temperature for reactor vessel materials due to neutron embrittlement (LRA Section 4.2.2)
- reflood thermal shock analysis of the reactor vessel (LRA Section 4.2.3)
- reflood thermal shock analysis of the reactor vessel core shroud (LRA Section 4.2.4)
- reactor vessel thermal limit analyses - operating pressure-temperature limits (LRA Section 4.2.5)
- reactor vessel circumferential weld examination relief (LRA Section 4.2.6)
- reactor vessel axial weld failure probability (LRA Section 4.2.7)
- irradiation assisted stress corrosion cracking (IASCC) of the recator vessel and its internals (LRA Section 4.7.6)
- stress relaxation of the core plate hold-down bolts (LRA Section 4.7.7)

4.2.1 Reactor Vessel Materials Upper Shelf Energy Reduction due to Neutron Embrittlement

4.2.1.1 Summary of Technical Information in the Application

In LRA Section 4.2.1, the applicant provided USE values for the limiting beltline materials. USE is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. Appendix G of 10 CFR Part 50 requires the predicted end of life (EOL)

Charpy impact test USE value for RV materials to be at least 50 ft-lb (absorbed energy), unless an approved analysis supports a lower value. The applicant stated that the initial unirradiated test data are not available for the BFN RVs to demonstrate a minimum 50 ft-lb USE by standard methods. Therefore, EOL fracture energy was evaluated by using the equivalent margin analysis (EMA) methodology described in General Electric (GE) NEDO-32205-A, “10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper-Shelf Energy in BWR-2 through BWR-6 Vessels,” which has been approved by the staff. According to the applicant, this analysis confirmed that an adequate margin of safety against fracture, equivalent to 10 CFR 50, Appendix G requirements, does exist. The EOL USE calculations satisfy the criteria of 10 CFR 54.3(a). As such, these calculations are a TLAA.

The RVs were originally licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The CLB calculations use calculated fluences that are lower than this limiting value. The applicant stated that the design basis value of 10^{19} n/cm^2 bounds calculated fluences for the original 40-year license term for each unit. The tests performed on RV materials provided limited Charpy impact data. It was not possible to develop original Charpy impact test USE values using the methods of 10 CFR Part 50, Appendix H and ASTM E23, “Methods for Notched Bar Impact Testing of Metallic Materials,” invoked by 10 CFR Part 50 Appendix G. Therefore, alternative methods approved by the staff in NEDO-32205-A were used to demonstrate compliance with the 10 CFR Part 50, Appendix G USE requirement.

Fluences were calculated for the RVs for the extended 60-year [54 EFPY (Effective Full-Power Year) for Unit 1; 52 EFPY for Units 2 and 3] licensed operating periods, using the methodology of NEDC-32983P, “General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation,” which was approved by the staff in an SER dated September 14, 2001. The applicant used bounding fluence calculation, for each unit which included an extended power uprate[2] (EPU). The applicant provided the results for one bounding calculation for each RV and determined the peak surface fluence of 1.95×10^{18} n/cm^2 and peak 1/4*t* fluence of 1.35×10^{18} n/cm^2 for Unit 1 vessel, and peak surface fluence of 2.3×10^{18} n/cm^2 and peak 1/4*t* fluence of 1.59×10^{18} n/cm^2 for Units 2 and 3 vessels. Peak fluences were calculated at the vessel inner surface (inner diameter), for purposes of evaluating USE. The value of neutron fluence was also calculated for the 1/4*t* location into the vessel wall measured radially from the inside diameter using Equation 3 from Paragraph 1.1 of RG 1.99, Revision 2. This 1/4*t* depth is recommended in the ASME Section XI, Appendix G, subarticle G-2120 as the maximum postulated defect depth. The applicant evaluated the EOL USE by an EMA using the 54 EFPY calculated fluence for Unit 1 and the 52 EFPY calculated fluence for Units 2 and 3. As documented in the staff’s SER, BWRVIP-74-A provided a generic EMA which demonstrated that BWR/3-6 plates and BWR/2-6 welds showing that percentage of reductions in USE of equal to or less than 23.5 percent and 39 percent, respectively, would meet the requirements of 10 CFR Part 50, Appendix G. The applicant provided results of the EMA for limiting welds and plates on the three RVs, which are summarized in LRA Tables 4.2.1.1 through 4.2.1.6. The applicant stated that the results are acceptable because the limiting USE percentage drop is less than the BWRVIP-74-A percentage drop acceptance criterion in all cases.

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[2]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

4.2.1.2 Staff Evaluation

Appendix G to 10 CFR Part 50, Section IV.A.1 requires, in part, that the reactor pressure vessel (RPV) beltline materials have Charpy USE values in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will ensure margins of safety against fracture equivalent to those required by ASME Code Section XI, Appendix G.

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted NEDO-32205-A to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME Code Section XI for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concluded that the topical report demonstrated that the evaluated materials have the margins of safety against fracture equivalent to ASME Code Section XI, Appendix G in accordance with 10 CFR Part 50, Appendix G. In that report, the BWROG derived through statistical analysis the unirradiated USE values for materials that originally did not have documented unirradiated Charpy USE values. Using these statistically-derived Charpy USE values, the BWROG predicted the USE values through 40 years of operation in accordance with RG 1.99, Revision 2. According to this RG, the decrease in USE is dependent upon the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE value in the transverse direction for base metal and along the weld for weld material was 35 ft-lb.

GE performed an update to the USE EMA, which is documented in Electric Power Research Institute (EPRI) TR-113596, “BWR Vessel and Internals Project (VIP) BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” BWRVIP-74, September 1999. The staff review and approval of EPRI TR-113596 was documented in a letter dated October 18, 2001, from Mr. C.I. Grimes to Mr. C. Terry. The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron irradiation using the methodology in RG 1.99, Revision 2. Using this methodology and a correction factor of 65 percent for conversion of the longitudinal properties to transverse properties, the lowest Charpy USE at 54 EFPY for all BWR/3-6 plates was projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical Position MTEB 5-2. The EMA acceptance criteria specified in the staff approved report BWRVIP-74, “BWR Vessel and Internals Project (BWRVIP), BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” are based on the percentage reduction in the unirradiated charpy USE values resulting from neutron radiation using the methodology in RG 1.99, Revision 2. The acceptance criteria that are specified in the BWRVIP-74 report indicate that the maximum allowable percentage reduction in USE value is 23.5 percent for the plates, and 39 percent for welds except for Linde 80 weld. Linde 80 welds are discussed later in this SER.

The staff’s review of LRA Section 4.2.1 identified an area in which additional information was necessary to complete the review of the reactor vessel materials USE reduction due to neutron embrittlement evaluation. The applicant responded to the staff’s request for additional information (RAI) as discussed below.

In RAI 4.2.1-1, dated December 1, 2004, the staff requested that the applicant provide the initial USE values, percentage reduction in USE values, percentage of copper, and 1/4*t* fluence at the end of the period of extended operation (including power uprate conditions) for all the plates and non-Linde 80 weld metals in the beltline region of the RVs. Since the analysis in the BWRVIP-74 is a generic analysis, the applicant submitted plant-specific information in LRA Tables 4.2.1.1 through 4.2.1.6 for BFN to demonstrate that the beltline plates and non-Linde 80 weld metals of the RVs meet the criteria in the BWRVIP-74 report at the end of the license renewal period. In its response, by letter January 31, 2005, the applicant stated that the initial USE values are not available for BFN; however, BFN has used the EMA method to demonstrate that the BFN vessels will maintain adequate fracture toughness throughout the period of extended operation. The LRA bounding value for EFPY is 54 EFPY for Unit 1 and 52 EFPY for Units 2 and 3. The values for all beltline materials for BFN are listed in Tables 4.2.1-1 through 4.2.1-3 of the applicant's response. The staff has verified the copper contents given in Tables 4.2.1-1 to 4.2.1-3 and concluded that applicant's response for all the beltline materials with the corresponding data in Reactor Vessel Integrity Data Base (RVID) is acceptable.

The applicant stated that the percentage reduction in the USE value for the limiting beltline plate base materials and non-Linde 80 beltline welds for all the units is less than the aforementioned acceptance criteria specified in BWRVIP-74. The staff also verified the reduction in the unirradiated USE values due to neutron radiation for the beltline base metals and non-Linde 80 beltline welds for all the units using the methodology in RG 1.99, Revision 2, and found that all the beltline materials meet the acceptance criteria specified in the staff-approved report BWRVIP-74, and 10 CFR Part 50, Appendix G. Therefore, the staff's concern described in RAI 4.2.1-1 is resolved.

The BWRVIP-74 establishes criteria for Linde 80 welds and other types of welds and base metals in the BWR RPVs. The criteria for Linde 80 welds require that the fracture toughness of the Linde 80 weld shall be established by using J-R curve based on copper and neutron fluence values. By letter dated November 21, 2005, the applicant revised LRA Table 4.2.1.1 to indicate that the limiting beltline circumferential weld for the BFN Unit 1 was made with Linde 80 flux. The applicant in its letter dated November 21, 2005, also provided the fracture toughness data (J-R curve based on the limiting copper and the neutron fluence at the end of the period of extended operation, which includes power uprate) and the $J_{applied}$ values for the Linde 80 weld, and concluded that the subject weld will maintain adequate fracture toughness during the extended period of operation. The staff verified the applicant's data and concluded that the BFN Unit 1 limiting circumferential Linde 80 weld would meet the acceptance criteria specified in the staff-approved BWRVIP-74 report and 10 CFR Part 50, Appendix G for the period of extended operation.

4.2.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV materials USE reduction due to neutron embrittlement in LRA Section A.3.1.1. On the basis of its review and the RAI response above, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on RV materials USE reduction due to neutron embrittlement and is, therefore, acceptable.

4.2.1.4 Conclusion

The staff reviewed the applicant's RAI response and TLAA on USE, as summarized in LRA Section 4.2.1, and determined that the RV beltline materials at BFN will continue to comply with the staff's USE requirements of 10 CFR Part 50, Appendix G throughout the periods of extended operation for the BFN units. The staff therefore concluded that the applicant's TLAA for USE is in compliance with the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on USE for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.2 Adjusted Reference Temperature for Reactor Vessel Materials due to Neutron Embrittlement

4.2.2.1 Summary of Technical Information in the Application

In LRA Section 4.2.2, the applicant summarized the ART determination for the RV materials due to neutron embrittlement. The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}), and a margin (M) term. The margin term is defined in RG 1.99, Revision 2. As addressed in RG 1.99, Revision 2, delta RT_{NDT} is a function of neutron fluence. Since neutron fluence changes with time, the determination of delta RT_{NDT} (and, therefore, ART) meets the criteria of 10 CFR 54.3(a) for being a TLAA.

As described in UFSAR Section 4.2, the RVs were licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The applicant stated that the CLB calculations use calculated fluences that are lower than this limiting value. The design basis value of 10^{19} n/cm^2 bounds calculated fluences for the original 40-year license term for all three units. The ART values were determined using the embrittlement correlations defined in RG 1.99, Revision 2.

The applicant calculated fluences for the RVs for the extended 60-year (54 EFPY for Unit 1; 52 EFPY for Units 2 and 3) licensed operating periods using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which was approved by the staff in an SER dated September 14, 2001. One bounding calculation was performed for each reactor vessel. Peak fluences, which included consideration of EPU conditions, were calculated at the vessel inner surface (inner diameter) for purposes of evaluating USE and ART. The neutron fluence values were also calculated for the 1/4*t* location into the vessel wall measured radially from the inside diameter using equation 3 from Paragraph 1.1 of RG 1.99, Revision 2. This 1/4*t* depth is recommended in the ASME Code Section XI, Appendix G, Subarticle G-2120 as the maximum postulated defect depth. The applicant calculated ART values for beltline materials 54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) based on the embrittlement correlation found in RG 1.99, Revision 2. The peak fluence, and ART values for the 60-year (54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) license operating period are presented in LRA Table 4.2.2-1. The applicant claimed that the limiting ARTs allow P-T limits that will provide reasonable operational flexibility.

4.2.2.2 Staff Evaluation

The applicant calculated the 54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) fluences for the RVs using the methodology of NEDC-32983P. Since this methodology is approved by the NRC, the calculated fluences provided in the LRA are acceptable. The applicant provided the results for one bounding calculation for each RV and determined the peak surface fluence of 1.95 x 10^{18} n/cm^2 and peak 1/4*t* fluence of 1.35 x 10^{18} n/cm^2 for, the Unit 1 vessel, and peak surface fluence of 2.3 x 10^{18} n/cm^2 and peak 1/4*t* fluence of 1.59 x 10^{18} n/cm^2 for, the Units 2 and 3 vessels. LRA Table 4.2.2.1 shows bounding fluence values for BFN for 54, 52 and 52 EFPYs of the operation, respectively.

The staff's review of LRA Section 4.2.2 identified areas in which additional information was necessary to complete the review of the ART values for RPV materials due to neutron embrittlement evaluation. The applicant responded to the staff's RAI as discussed below.

In RAIs 4.2.2(A), and 4.2.2(B), dated December 1, 2004, the staff requested that the applicant provide an explanation addressing the following issues:

a. The staff requested that the applicant explain why Unit 1 was assumed to achieve 54 EFPYs of operation in a 60-year span given its operating history. Additionally, the staff requested that the applicant provide an explanation for having a peak surface fluence value of 1.95 x 10^{18} n/cm^2 (E > 1.0 MeV) for Unit 1, while Units 2 and 3 achieve 2.3 x 10^{18} n/cm^2 (E > 1.0 MeV) at the end of 60 years.

   After reviewing the applicant's response, dated January 31, 2005, the staff determined that the applicant performed fluence calculations for Unit 1 assuming 54 EFPY of operation and for Units 2 and 3 assuming 52 EFPY of operation. Based on the peak surface and 1/4*t* fluence values, the applicant calculated USE and ART values for the limiting beltline material for each unit. The applicant stated that the reason the reported peak fluence for Unit 1 is lower than the fluence values for Units 2 and 3 is that the maximum delta RT_{NDT} and ART occurs in the circumferential weld material for Unit 1, which is located away from the peak vessel fluence location, whereas for both Units 2 and 3 maximum delta RT_{NDT} and ART occurs in the axial weld materials which corresponds to the peak fluence. Therefore, the reported peak fluence for Unit 1 has an applied axial correction factor of 0.81 and Units 2 and 3 do not have the axial correction factor. The applicant also indicated that 54 EFPY was selected for BFN units as a bounding value as part of the EPU[1] evaluation. For consistency with the EPU evaluation, the 54 EFPY value was incorporated into the LRA. The ART values are listed in Tables 4.2.2-1 through 4.2.2-6 of the applicant's response.

   The staff reviewed the applicant's response and found the explanation for using the fluence values cited for Units 1, 2, and 3 acceptable because it accounts for differences in weld location and neutron flux for each unit. The staff found that this approach is acceptable as it identifies the maximum ART values for all three units. Therefore, the staff's concern described in RAI 4.2.2 (A) is resolved.

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[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

b. The staff requested that the applicant provide the initial RT_{NDT} and ART values at 1/4t and vessel ID surface at the end of the period of the extended operation for all the materials in the beltline region of the BFN RVs.

The applicant provided information on the above items in Tables 4.2.2-1 to 4.2.2-6 of its response dated January 31, 2005. The staff verified the percentages of copper and nickel and the initial RT_{NDT} given in the applicant's response for all the beltline materials with the corresponding data in RVID and found them acceptable. The staff also verified the accuracy of the ART values for all the beltline materials using the methodology in RG 1.99, Revision 2 and found them acceptable. Therefore, the staff's concern described in RAI 4.2.2 (B) is resolved.

4.2.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of ART for RV materials due to neutron embrittlement in LRA Section A.3.1.2. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on ART for RV materials due to neutron embrittlement and is, therefore, acceptable.

4.2.2.4 Conclusion

The staff reviewed the applicant's TLAA on the calculation of ART values, as summarized in LRA Section 4.2.2 and the RAI response dated January 31, 2005, and determined that the applicant's calculation of the ART values for the RV beltline materials, as projected through the periods of extended operation for BFN, Units 1, 2, and 3, is in conformance with the recommended guidelines of RG 1.99, Revision 2. The staff therefore concluded that the applicant's TLAA for calculation of the ART values meet the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on ART calculations for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.3 Reflood Thermal Shock Analysis of the Reactor Vessel

4.2.3.1 Summary of Technical Information in the Application

The applicant stated that UFSAR Section 3.3.5 includes an EOL thermal shock analysis performed on the RVs for a design basis loss of coolant accident (LOCA) followed by a LPCI system initiation. The effects of embrittlement assumed in this thermal shock analysis will change with an increase in the licensed operating period. The applicant stated that this analysis satisfies the criteria of 10 CFR 54.3(a). As such, this analysis is a TLAA.

For the current operating period, a thermal shock analysis was originally performed on the RV components. The analysis assumed a design basis LOCA followed by LPCI system initiation and accounted for the full effects of neutron embrittlement at the end of the current license term of 40 years. The current analysis assumes EOL material toughness, which in turn depends on EOL ART values. The critical location for fracture mechanics analysis is at one quarter of the vessel thickness (from the inside, 1/4*t*). For this event, the peak stress intensity occurs approximately 300 seconds after the LOCA. The applicant stated that the analysis shows that 300 seconds into the thermal shock event, the temperature of the vessel wall at 1.5 inches deep (which is 1/4*t*) is approximately 400 °F. The ART values, described in LRA Section 4.2.2 and tabulated in Table 4.2.2.1, list the ART values for the limiting weld metal of the RVs. The highest calculated RV beltline material ART value is 167.7 °F (Unit 1). Using the equation for K_{IC} presented in ASME Section XI Appendix A and the maximum ART value, the material reaches upper shelf (a K_{IC} value of 200 ksi √in) at 272 °F, which is well below the 400 °F, 1/4*t* temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the applicant claimed that the projected analysis is valid for the period of extended operation.

4.2.3.2 Staff Evaluation

The analysis assumes EOL material toughness, which in turn depends on EOL ART. The critical location for fracture mechanics analysis is at the 1/4*t* location. For the reflood thermal shock analysis of the RV, the peak stress intensity occurs at approximately 300 seconds after the LOCA. At that time, the temperature at 1/4*t* is approximately 400 °F, which is much higher than the 54 EFPY ART value167.7 °F for the limiting material of all the three BFN vessels. Therefore, the staff concurred with the applicant that the revised thermal shock analysis of the BFN vessels is valid for the period of extended operation because the ART for the limiting beltline plate material is 167.7 °F for Unit 1, which is below the 400 °F at 1/4*t* temperature predicted for the thermal shock event at the time of peak stress intensity. The reflood thermal shock analysis is, therefore, bounding and valid for the period of extended operation.

4.2.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the “programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation.” The applicant provided UFSAR supplement summary description of reflood thermal shock analysis of the RV in LRA Section A.3.1.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reflood thermal shock analysis of the RV and is, therefore, acceptable.

4.2.3.4 Conclusion

The staff reviewed the applicant’s TLAA on reflood thermal shock analysis of the RV for a design basis LOCA and concluded that the applicant has demonstrated that the limiting beltline material will have adequate fracture toughness when exposed to stresses due to reflood thermal shock due to LOCA. The staff determined that this revised analysis for the period of extended operation meets the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1).

4.2.4 Reflood Thermal Shock Analysis of the Reactor Vessel Core Shroud

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 states that the radiation embrittlement may affect the ability of RV internals, particularly the core shroud, to withstand a LPCI thermal shock transient. The applicant stated that the analysis of core shroud strain due to reflood thermal shock is based on the calculated lifetime neutron fluence. In the thermal shock analysis of the RV core shrouds, the applicant considered the location on the inside surface of the core shroud opposite the midpoint of the fuel centerline as the location most susceptible to damage during a LPCI thermal shock transient because it receives the maximum irradiation. This analysis satisfies the criteria of 10 CFR 54.3(a). As such, this analysis is a TLAA.

The applicant stated that it used the approved fluence methodology discussed in LRA Section 4.2.2, and the 54 EFPY fluence at the most irradiated point on the core shroud was calculated to be 5.34 x 10^{21} n/cm^2 (E > 1 MeV) for BFN units. The maximum thermal shock stress due to a LPCI transient in this region will be 155,700 psi equivalent to 0.57 percent strain. This strain range of 0.57 percent was calculated at the midpoint of the shroud when it is exposed to 54 EFPY fluence. The applicant compared the calculated strain range with the measured values of percentage of elongation for annealed Type 304 stainless steel irradiated to 8 x 10^{21} n/cm^2 (E > 1 MeV). The measured value of percent elongation for stainless steel weld metal is 4 percent for a temperature of 297 °C (567 °F) with a neutron flux of 8 x 10^{21} n/cm^2 (E > 1 MeV), while the average value for base metal at 290 °C (554 °F) is 20 percent. The applicant concluded that the measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57 percent and that the calculated thermal shock strain at the most irradiated location is acceptable considering the embrittlement effects for the period of extended operation.

4.2.4.2 Staff Evaluation

In the thermal shock analysis of RV core shrouds, the applicant considered the location on the inside surface of the core shroud opposite the midpoint of the fuel centerline as a location most susceptible to damage during a LPCI thermal shock transient because it receives the maximum irradiation. This fluence is calculated using the methodology of NEDC-32983P, “General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation,” which has been approved by the staff.

The staff’s review of LRA Section 4.2.4 identified areas in which additional information was necessary to complete the review of the reflood thermal shock analysis of the reactor vessel core shroud evaluation. The applicant responded to the staff’s RAI as discussed below.

In RAI 4.2.4-1(A), dated December 1, 2004, the staff stated that in LRA Section 4.2.4, “Reflood Thermal Shock Analysis of the RV Core Shroud and Repair Hardware,” the applicant stated that the total integrated neutron flux at the end of 54 EFPY at the shroud inside surface is expected to be 5.34 x 10^{21} n/cm^2 (E > 1 MeV). Therefore, the staff requested that the applicant provide an explanation of whether this value is bounding at the inside shroud surface for all three units. If so, submit information whether the neutron fluence values are estimated based on the implementation of EPU[1].

In its response, by letter January 31, 2005, the applicant stated that the calculation of shroud fluence, 5.34×10^{21} n/cm^2 (E > 1 MeV) is based on the inner diameter peak flux of 3.14×10^{12} n/cm^2-sec (E > 1 MeV) for 54 EFPY, which is the lifetime used for Unit 1. Since lifetime used for BFN Units 2 and 3 is 52 EFPY, 5.34×10^{21} n/cm^2 (E > 1 MeV) fluence from Unit 1 is bounding for all the BFN units. The fluence value for the shroud inner diameter was based on the implementation of EPU conditions. After the review, the staff concurred with the applicant, and accepted the conservative bounding fluence value of 5.34×10^{21} n/cm^2 (E > 1 MeV) for all the three units.

RAI 4.2.4-1(B) and the applicant's response are addressed in SER Section 4.7.6.2 under core shroud subsection.

In RAI 4.2.4-1(C), dated December 1, 2004, the staff stated that the applicant calculated thermal strain resulting from the LPCI reflood thermal shock transient in the core shroud region. The applicant compared the calculated thermal strain with the measured values of percentage of elongation of annealed Type 304 stainless steel irradiated to 8×10^{21} n/cm^2 (E > 1.0 MeV). In a previous analysis performed by Dresden/Quad Cities, the applicant used the percentage reduction in area as a criterion to evaluate the thermal strain. Therefore, the staff requested that the applicant provide information on the measured percentage reduction in area values for the irradiated Type 304 stainless steel. The applicant should compare the results of the analysis obtained from using the reduction in area, with the ones using the percentage of elongation, and justify which of these properties is more appropriate to use in evaluating the local thermal shock strain associated with the reflood thermal shock event at the most irradiated core shroud region.

In its response, by letter January 31, 2005, the applicant submitted the following reduction in area and elongation values for irradiated stainless steel materials:

<u>Reduction in Area</u>

Fluence (n/cm^2, E>1MeV)	Test Temperature (°F)	Reduction in Area (%)
1×10^{21}	550	40
6.9×10^{21}	750	52.5

[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

Elongation

Material	Fluence n/cm^2, (E>1MeV)	Test Temperature (°F)	Elongation (%)
Base	8 x 10^{21}	554	20
Weld	8 x 10^{21}	567	4

The applicant stated that the bounding shroud fluence (Unit 1) is 5.34 x 10^{21} n/cm^2 (E >1 MeV) for BFN, and the listed ductility values bound all three BFN shrouds. As described in LRA Section 4.2.4, the maximum thermal shock stress results in a calculated thermal shock strain amplitude of 0.57 percent. Both reduction in area and elongation values, which are values at failure, are significantly in excess of the calculated thermal shock strain at the most irradiated location. While the analysis indicates that either measure of ductility is acceptable for the period of extended operation, reduction in area is a more appropriate measure of ductility for the reflood thermal shock event. The strain associated with the reflood thermal shock event is very localized and is constrained by the surrounding bulk material. As such, it is similar to the triaxial stress condition present in the neck region (where the area reduction is taking place) during a tensile test. The percentage reduction in area is a measure of this triaxial stress state and, as such, is the most appropriate property for evaluating the effect of thermal shock on the RV core shroud. This staff position was previously approved for Dresden and Quad Cities LRA SER (NUREG-1796). The staff concluded that the thermal shock strain associated with the LOCA is less than the reduction in area or elongation, which would be expected to fail the shroud at the highest fluence point. Therefore, the staff concluded that the core shroud will have sufficient ductility during the reflood thermal shock transient during the period of extended operation. The staff accepts the applicant's analysis for the BFN units.

4.2.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of reflood thermal shock analysis of the RV core shroud in LRA Section A. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reflood thermal shock analysis of the RV core shroud and is, therefore, acceptable.

4.2.4.4 Conclusion

The staff reviewed the applicant's TLAA on reflood thermal shock analysis of the RV core shroud and the applicant's responses to the RAIs and concluded that the applicant has demonstrated that the calculated thermal shock strain at the most irradiated portion of the core shroud is acceptable. The staff also accepted the applicant's conservative methodology in establishing the integrity of the most irradiated location of the core shroud during a low-pressure coolant injection thermal shock event. The staff determined that the revised analysis for the period of extended operation meets the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1).

4.2.5 Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limits

4.2.5.1 Summary of Technical Information in the Application

In LRA Section 4.2.5, the applicant addressed the RV thermal limit analysis. The ART value is the sum of initial RT_{NDT} + delta RT_{NDT} + margins for uncertainties at a specific location. Neutron embrittlement increases the ART value. Thus, the minimum metal temperature at which an RV is allowed to be pressurized increases. The ART value of the limiting beltline material is used to correct the beltline P-T limits to account for irradiation effects. Appendix G of 10 CFR Part 50 requires RV thermal limit analyses to determine operating P-T limits for three categories of operation: (1) hydrostatic pressure tests and leak tests, referred to as Curve A; (2) non-nuclear heatup/cooldown and low-level physics tests, referred to as Curve B; and (3) core critical operation, referred to as Curve C. P-T limits are developed for three vessel regions: the upper vessel region, the core beltline region, and the lower vessel bottom head region. The calculations associated with generation of the P-T curves satisfy the criteria of 10 CFR 54.3(a). As such, this topic is a TLAA.

The applicant stated that the BFN Technical Specifications Section 3.4.9 contains P-T limit curves for heatup, cooldown, criticality, and inservice leakage and hydrostatic testing. According to the applicant, limits are also imposed on the maximum rate of change of reactor coolant temperature. The P-T limit curves are currently calculated for 12 EFPY (Unit 1), 17.2 EFPY (Unit 2) and 13.1 EFPY (Unit 3) operating periods. The applicant stated that new P-T limits will be calculated and submitted for approval prior to the start of extended operation.

4.2.5.2 Staff Evaluation

The applicant plans to calculate vessel P-T limit curves for all BFN units and submit them to the staff for approval before the start of the period of extended operation using an approved fluence methodology. By letter dated December 6, 2004, the applicant submitted updated P-T curves for Unit 1, which are currently being reviewed by the staff. The applicant stated that the P-T curves for Units 2 and 3 were approved by the staff as documented in safety evaluations dated March 10, 2004. The applicant's CLB allows the development of P-T limit curves consistent with the 2000 Edition, 2001 Addenda of Section XI of the ASME Code. The applicant stated that it will manage the P-T limits using approved fluence calculations when there are changes in power of core design in conjunction with surveillance capsule results from the BWRVIP integrated surveillance program. The staff found the applicant's plan to manage the P-T limits acceptable because the change in P-T curves will be implemented by the license amendment process (i.e., modifications of technical specifications) and will meet the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

4.2.5.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV thermal limit analyses: operating temperature and pressure limits in LRA Section A.3.1.5. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reactor vessel thermal limit analyses: operating P-T limits and is, therefore, acceptable.

4.2.5.4 Conclusion

The staff reviewed the applicant's TLAA on P-T limits, as summarized in LRA Section 4.2.5 and determined that the applicant will generate the P-T limits for the periods of extended operation for BFN. The staff therefore concluded that the applicant's TLAA for the BFN P-T limits will meet the requirements of 10 CFR 54.21(c)(1)(ii) when the P-T limits for the periods of extended operation are generated and incorporated into the BFN technical specifications and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on P-T limits for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.6 Reactor Vessel Circumferential Weld Examination Relief

4.2.6.1 Summary of Technical Information in the Application

LRA Sections 4.2.6 and A.3.1.6 discuss inspection of the RV circumferential welds. These sections of the LRA indicate that the applicant will use an approved relief from ultrasonic testing of RV circumferential shell welds. The applicant stated that the relief from RV circumferential weld examination requirements under GL 98-05 is based on probabilistic assessments that predict an acceptable probability of failure per reactor operating year. The analysis is based on RV metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period. The applicant stated that Units 2 and 3 have received this relief for the remainder of their current 40-year licensed operating periods. Unit 1 submitted a relief request (currently under review by the staff) for the remainder of its 40-year licensed operating period. The circumferential weld examination relief analyses meet the requirements of 10 CFR 54.3(a). As such, they are a TLAA.

The basis for this relief request was an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license, based on topical report BWRVIP-05, "Reactor Vessel Shell Weld Inspection Guidelines," and the extent of neutron embrittlement. The anticipated changes in metallurgical conditions expected over the extended licensed operating period require an additional analysis for the period of extended operation and approval by the staff to extend this relief request.

The staff evaluation of BWRVIP-05 utilized the favor code to perform a probabilistic fracture mechanics (PFM) analysis to estimate the RPV shell weld failure probabilities. Three key assumptions of the PFM analysis were (1) the neutron fluence was the estimated end-of-license mean fluence, (2) the chemistry values were mean values based on vessel types, and (3) the potential for beyond design basis events (DBEs) was considered. LRA Table 4.2.6.1 provides a comparison of Units 2 and 3 RV limiting circumferential weld parameters to those used in the staff evaluation of BWRVIP-05 for the first two key assumptions. Data provided in LRA Table 4.2.6.1 were supplied from Tables 2.6.4 and 2.6.5 of the final safety evaluation of the BWRVIP-05 report.

For Units 2 and 3, the fluence is equivalent to that used in the staff analysis. However, Units 2 and 3 weld materials have significantly lower copper values (0.09 vs. 0.31) than those used in the NRC analysis. As a result, the shifts in reference temperature for Units 2 and 3 are lower than the 64 EFPY shift from the staff SER analysis. In addition, the unirradiated reference temperatures for both units are significantly lower. The combination of initial RT_{NDT} and delta RT_{NDT} without margin yields mean RT_{NDT} values for Units 2 and 3 that are considerably lower than the staff mean analysis values. Based on this analysis, the applicant concluded that the RV conditional failure probability is bounded by the staff analysis. The applicant claimed that the procedures and training used to limit cold over-pressure events will be the same as those approved by the staff when the applicant requested the relief for the current license term for Units 2 and 3.

4.2.6.2 Staff Evaluation

The technical basis for relief is discussed in the staff's final SER concerning the BWRVIP-05 report, which is enclosed in a July 28, 1998, letter from Mr. G.C. Laines (NRC) to Mr. C. Terry (BWRVIP Chairman). In this letter, the staff concluded that since the failure frequency for RV circumferential welds in BWR plants is significantly below the criterion specified in RG 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," and below the core damage frequency of any BWR plant, the continued inspection would result in a negligible decrease in an already acceptably low value of RV failure. Therefore, elimination of the inservice inspection (ISI) for RV circumferential welds is justified. The staff's letter indicated that BWR applicants may request relief from ISI requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RV welds by demonstrating that (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the staff's July 28, 1998 evaluation, and (2) the applicants have implemented operator training and established procedures that limit the frequency of cold over-pressure events to the frequency specified in the staff's SER. The letter indicated that the requirements for inspection of circumferential RV welds during an additional 20-year license renewal period would be reassessed, on a plant-specific basis, as part of any BWR LRA. Therefore, the applicant must request relief from inspection of circumferential welds during the license renewal period per 10 CFR 50.55a.

Section A.4.5 of the BWRVIP-74 report indicates that the staff's SER of the BWRVIP-05 report conservatively evaluated the BWR RVs to 64 EFPY, which is 10 EFPY greater than what is realistically expected for the end of the license renewal period. The staff used the mean RT_{NDT} value for materials to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPY in the staff SER dated July 28, 1998. The neutron fluence used in this evaluation was the neutron fluence at the clad-weld (inner) interface.

Since the staff analysis discussed in the BWRVIP-74 report is a generic analysis, the applicant submitted plant-specific information to demonstrate that the beltline materials meet the criteria specified in the report. To demonstrate that the vessels for Units 2 and 3 have not become embrittled beyond the basis for the relief, the applicant, in LRA Table 4.2.6.1, supplied a comparison of 52 EFPY material data for the limiting BFN circumferential welds with that of the 64 EFPY reference case in Appendix E of the staff's SER of the BWRVIP-05 report. The BFN material data included amounts of copper and nickel, chemistry factor, the neutron fluence, delta RT_{NDT}, initial RT_{NDT}, and mean RT_{NDT} of the limiting circumferential weld at the end of the renewal period. The staff verified the data for the copper and nickel contents and the initial RT_{NDT} values for Units 2 and 3 beltline materials by comparing them with the corresponding data in the RVID maintained by the staff. The 52 EFPY mean RT_{NDT} value for Units 2 and 3 is 25 °F. The staff checked the applicant's calculations for the 52 EFPY mean RT_{NDT} values for the circumferential welds using the data presented in LRA Table 4.2.6.1 and found them accurate. These 52 EFPY mean RT_{NDT} values for Units 2 and 3 are less than the 64 EFPY mean RT_{NDT} value of 129.4 °F used by the staff for determining the conditional failure probability of a circumferential weld. The 64 EFPY mean RT_{NDT} value from the staff SER dated July 28, 1998, is for a Babcock and Wilcox (B&W) weld, because B&W welded the circumferential welds in the vessels. Since the BFN 52 EFPY mean RT_{NDT} values are less than the 64 EFPY value from the staff SER dated July 28, 1998, the staff concluded that the BFN RV conditional failure probabilities are bounded by the staff analysis.

The applicant stated that the procedures and training used to limit cold over-pressure events will be the same as those approved by the staff when the applicant requested relief for the current license period, but it did not explicitly cite a document that supports this statement. The applicant stated that the procedure and training requirements identified in the applicant's request to use the BWRVIP-05 report are provided in the document, "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Alternative to Inspection of Reactor Pressure Vessel Circumferential Welds, BFN Power Station, Units 2 and 3," (attached to staff letter to TVA; "Browns Ferry Nuclear Plant Unit 2, Relief Request 2-ISI-9, Alternatives for Examination of Reactor Pressure Vessel Shell Welds (TAC No. MA8424)," August 14, 2000; and staff letter to the applicant, "Browns Ferry Nuclear Plant Unit 3, Relief Request 3-ISI-1, Revision 1, Alternatives for Examination of Reactor Pressure Vessel Shell Welds (TAC No. MA5953)," November 18, 1999. The applicant further stated that LRA Section 4.2.6, and associated LRA Section A.3.1.6, reference the safety evaluation request letters identified above. The staff found the response acceptable because the applicant identified the requested references and commits to include them in LRA Sections 4.2.6 and A.3.1.6.

By letter dated May 12, 2004, the applicant submitted a relief request concerning the examination of the Unit 1 RV circumferential welds for the current license period.

In RAI 4.2.6-1, dated December 1, 2004, the staff requested that the applicant provide the RV circumferential weld examination relief analyses for Unit 1. In its response, by letter January 31, 2005, the applicant submitted the following relief analyses related to the Unit 1 RV circumferential weld examination:

> The following table provides a comparison of the BFN Unit 1 RV limiting circumferential weld parameters to those used in the NRC evaluation of BWRVIP-05 for the first two key assumptions. Data provided in this table was supplied from Tables 2.6.4 and 2.6.5 of the Final Safety Evaluation of the BWRVIP-05 Report (NRC letter from Gus C. Lainas to Carl Terry, Niagara Mohawk Power Company, BWRVIP Chairman, "Final Safety Evaluation of the BWRVIP Vessel and Internals Project BWRVIP-05 Report," (TAC No. M93925), July 28, 1998.

Group	B & W 64 EFPY	BFN Unit 1 54 EFPY
Cu %	0.31	0.27
Ni %	0.59	0.6
CF	196.7	184
Fluence at clad/weld interface 10^{19} n/cm^2	0.19	0.2
Delta RT_{NDT} without margin (°F)	109.4	104
Initial RT_{NDT} (°F)	20	20
Mean RT_{NDT} (°F)	129.4	124
P (F/E) NRC	4.83×10^{-4}	-------------------------
P (F/E) BWRVIP	---------------------	-----------------------

> The fluence assumed for Unit 1 is very conservative based on an extended shutdown period from 1985 to a scheduled restart in 2007, which will result in less than 32 EFPY of vessel exposure through the end of the extended period of operation. However, TVA conservatively chose to use the higher exposure of 54 EFPY to simplify the basis for the Unit 1 vessel evaluations. As shown in the table, the Unit 1 unirradiated weld RT_{NDT} is identical to the reference B&W plant unirradiated weld RT_{NDT} used in the NRC analysis, and the Unit 1 fluence value is approximately equivalent to that used in the NRC analysis. However, because the Unit 1 chemistry factor is less than the reference B&W plant, the mean RT_{NDT} values for Unit 1 at 54 EFPY are bounded by the 64 EFPY Mean RT_{NDT} assumed by the NRC in its analysis. Accordingly, Unit 1 is bounded by the conditional failure probability calculated by the Staff for the limiting B&W vessel. An extension of this relief for the 60-year period will be submitted to the NRC for approval prior to entering the period of extended operation.

The staff verified the accuracy of the of the mean RT_{NDT} for the limiting beltline circumferential weld at Unit 1 and found it acceptable. In the staff's evaluation of the BWRVIP-05 report, a fluence of 0.19×10^{19} n/cm^2 for B&W RVs was used for 64 EFPY and the corresponding delta RT_{NDT} value is 109.4 °F. The delta RT_{NDT} value for the limiting beltline weld metal of Unit 1 is less than the limiting delta RT_{NDT} value in the staff's evaluation of BWRVIP-05 report, which is conservative. Therefore, the applicant's calculated mean RT_{NDT} value for the limiting beltline weld metal is acceptable and meets the requirements specified in staff's approved SER for the BWRVIP-05 report.

The staff's SER for the BWRVIP-05 report provides a limiting conditional failure probability of 4.83×10^{-4} per reactor-year for a limiting plant-specific mean RT_{NDT} of 129.4 °F for B&W fabricated RVs. The low temperature over-pressure (LTOP) transient frequency is the frequency of the transient occurring, determined as 10^{-3} per reactor-year in the evaluation of BWRVIP-05 report. The conditional failure probability is the probability of failure, if the event were to occur. The vessel failure frequency is the product of conditional failure probability and LTOP frequency. Comparing the information in the RVID with that submitted in the analysis, the staff confirmed that the mean RT_{NDT} of the circumferential welds at Unit 1 is projected to be 124 °F at the end of the period of extended operation (54 EFPY). In this evaluation, the chemistry factor, delta RT_{NDT}, and mean RT_{NDT} were calculated consistent with the guidelines of RG 1.99, Revision 2. Since the calculated value of mean RT_{NDT} for the circumferential welds at Unit 1 is lower than that for the limiting plant-specific case for B&W fabricated RVs, the vessel failure frequencies of the Unit 1 circumferential welds is less than 4.83×10^{-7} per reactor-year.

The staff found that the applicant's evaluation for this TLAA is acceptable because the BFN 54 EFPY conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the staff SER dated July 28, 1998, and the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation. This analysis satisfies the evaluation requirements of the staff SER dated July 28,1998; however, the applicant is still required to request relief for the circumferential weld examination for the period of extended operation in accordance with 10 CFR 50.55a.

4.2.6.3 UFSAR Supplement

The applicant's UFSAR supplement summary description for the TLAA on RV circumferential weld examination relief appropriately describes that the conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the staff SER dated July 28, 1998, and the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation for Units 2 and 3. Since the UFSAR supplement summary description adequately describes the TLAA for Units 2 and 3, the staff concluded that the UFSAR supplement summary description for the TLAA on RV circumferential weld examination relief for Units 2 and 3 is acceptable. In addition, in a letter dated May 25, 2005, the applicant stated that the UFSAR supplement summary description also includes Unit 1 as shown in the revised supplement A.3.1.6.

4.2.6.4 Conclusion

The staff reviewed the applicant's TLAA on RV circumferential weld examination relief, as summarized in LRA Section 4.2.6, and determined that the applicant appropriately explained that the conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the SER on the BWRVIP-05 report, dated July 28, 1998, and that the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation for BFN. However, the staff concluded that the LRA Section A.3.1.6 should include circumferential weld examination analysis for Unit 1. The staff, therefore, concluded that the applicant's LRA Section 4.2.6 on TLAA, and LRA Section A.3.1.6 for the BFN RV circumferential weld examination relief will meet the requirements of 10 CFR 54.21(c)(1)(ii), except as noted above.

4.2.7 Reactor Vessel Axial Weld Failure Probability

4.2.7.1 Summary of Technical Information in the Application

LRA Section 4.2.7 discusses the BWRVIP recommendations for inspection of RV shell welds and contains generic analyses supporting a staff SER conclusion that the axial weld failure rate is no more than 5 x 10^{-6} per reactor year. The applicant stated that the supporting evaluations described in the LRA only apply to Units 2 and 3. The axial weld failure probability analysis meets the requirements of 10 CFR 54.3(a). As such, it is a TLAA.

The applicant compared the limiting axial weld properties at 52 EFPY for Units 2 and 3 with the limiting axial weld properties provided in the supplement to NRC SER for BWRVIP-05. The limiting axial welds at Units 2 and 3 are all electroslag welds with similar chemistry. The Units 2 and 3 limiting weld chemistry, chemistry factor, and 52 EFPY mean RT_{NDT} values are within the limits of the values assumed in the analysis performed by the staff in the BWRVIP-05 SER supplement. The applicant concluded that the probability of failure for the axial welds is bounded by the staff evaluation.

4.2.7.2 Staff Evaluation

In its July 28, 1998, letter to Mr. C. Terry, the BWRVIP Chairman, the staff identified a concern about the failure frequency of axially-oriented welds in BWR RVs. In response to this concern, in letters dated December 15, 1998, and November 12, 1999, the BWRVIP supplied evaluations of axial weld failure frequency. The staff's SER on these analyses is enclosed in a March 7, 2000, letter from Mr. J. Strosnider (NRC) to Mr. C. Terry, (BWRVIP Chairman). The staff performed a generic analysis using Pilgrim Nuclear Station SER as a model for BWR RVs that were fabricated with electroslag welds, and demonstrated that a mean RT_{NDT} of 114 °F resulted in a failure frequency of 5 x 10^{-6} per reactor-year of operation. The applicant calculated, and the staff confirmed, that the limiting axial weld mean RT_{NDT} value for Units 2 and 3 at 52 EFPY is 108 °F, which supports the conclusion that the failure frequencies for Units 2 and 3 will be less than 5 x 10^{-6} per reactor-year of operation at the end of their period of extended operation. Therefore, this analysis is acceptable.

In RAI 4.2.7-1, dated December 1, 2004, the staff requested that the applicant provide an evaluation for the RV axial weld failure probability analyses for Unit 1 for the current license period, and the period of extended operation. In its response to RAI 4.2.7-1, by letter dated January 31, 2005, the applicant provided the following evaluation on the RV axial weld failure probability analysis for Unit 1:

> The table provided below compares the limiting axial weld 54 EFPY properties for Unit 1 against the values taken from Table 2.6.5 found in the NRC SER for BWRVIP-05 and associated supplement to the SER (NRC letter from Jack R. Strosnider, to Carl Terry, BWRVIP Chairman, "Supplement to Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report," (TAC No. MA3395), March 7, 2000). The SER supplement required the limiting axial weld to be compared with data found in Table 3 of the document. For Unit 1 the comparison was made to the 'Mod 2' plant information. The supplemental SER stated that the 'Mod 2' calculations most closely match the 5 x 10^{-6} RV failure frequency.

Effects of Irradiation on RV Axial Weld Properties BFN Unit 1:

Value	NRC BWRVIP-05 SER MOD 2	BFN Unit 1 54 EFPY
Cu %	0.219	0.24
Ni %	0.996	0.37
CF	------	141
Fluence at clad/weld interface 10^{19} n/cm^2	0.148 (Peak Axial Fluence)	0.24
ΔRT_{NDT} without margin (^{0}F)	116	86
$RT_{NDT(U)}$ (°F)	-2	23
Mean RT_{NDT} (°F)	114	109
P (F/E) NRC	5.02×10^{-6}	Not Calculated

The limiting axial weld is an electroslag weld with similar chemistry. The Unit 1 limiting weld chemistry, chemistry factor, and 54 EFPY mean RT_{NDT} values are within the limits of the values assumed in the analysis performed by the NRC staff in the BWRVIP-05 SER supplement and the 64 EFPY limits and values obtained from Table 2.6.5 of the SER. Therefore, the probability of failure for the axial welds is bounded by the NRC evaluation.

In this evaluation, the chemistry factor delta RT_{NDT} and mean RT_{NDT} were calculated consistent with the guidelines of RG 1.99, Revision 2. The applicant calculated, and the staff confirmed, that the limiting axial weld mean RT_{NDT} value for Unit 1 at 54 EFPY is 109 °F. This value is lower than that for the limiting mean RT_{NDT} value of 114 °F in the staff's evaluation of BWRVIP-05. Therefore, the staff concluded that the failure frequencies for Unit 1 axial welds will be less than 5×10^{-6} per reactor-year of operation. The probability of failure for the axial welds is bounded by the staff evaluation.

4.2.7.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV axial weld failure probability in LRA Section A.3.1.7. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on RV axial weld failure probability and is, therefore, acceptable. In addition, in a letter dated May 25, 2005, the applicant stated that the UFSAR supplement summary description also includes Unit 1 as shown in the revised supplement A.3.1.7.

4.2.7.4 Conclusion

The staff reviewed the applicant's TLAA on the evaluation of RV axial weld failure probabilities, as summarized in LRA Section 4.2.7, and determined that the applicant appropriately describes that the analyses of the conditional failure probabilities for the BFN Units 2 and 3 RV axial welds is bounded by the NRC analysis in the staff SER on the BWRVIP-05 report, dated July 28, 1998. However, the UFSAR supplement summary description in LRA Section A.3.1.7 should include the analysis on the conditional failure probabilities for the Unit 1 RV axial welds. The staff therefore concluded that the applicant's LRA Sections 4.2.7, and A.3.1.7 related to the analysis of the conditional failure probabilities for the BFN units RV axial welds are acceptable. The staff concluded that the analysis of the RV axial weld failure probability for the BFN units will meet the requirements of 10 CFR 54.21(c)(1)(ii), except as noted above.

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. The GALL Report identifies fatigue aging related effects that require evaluation as possible TLAAs, pursuant to 10 CFR 54.21(c). Each of these is summarized in the SRP-LR and presented in LRA Section 4.

4.3.1 Reactor Vessel Fatigue Analysis

4.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.1, "Reactor Vessel Fatigue Analyses," the applicant stated that the original pressure vessel stress report included ASME Code Section III fatigue analyses of the RV components based on a set of design basis transients and corresponding cycles, which are listed in UFSAR Section 4.2.5. The analyzed components consisted of the vessel support skirt, shell, upper and lower heads, closure flanges, nozzles and penetrations, nozzle safe ends, and closure studs. The original 40-year analysis demonstrated that the cumulative usage factors (CUFs) for these components are below the ASME Code Section III limiting value of 1.0. A re-analysis was performed for BFN to determine the CUFs of these components under EPU and Maximum extended load line limit analysis conditions, for 60 years of operation. LRA Table 4.3.1.1 lists the results of this re-analysis for seven bounding reactor vessel components. These components are the recirculation outlet nozzle, recirculation inlet nozzle, feedwater nozzle, core spray nozzle, the support skirt, the closure stud bolts, and the vessel shell. This table shows that for Units 2 and 3, the recirculation outlet nozzles, the feedwater nozzles, the support skirts and the closure stud bolts, all have 60-year projected CUFs that exceed the ASME Code Section III Class 1 limiting value of 1.0. These results also bound the projected CUFs for Unit 1.

The applicant stated that fatigue aging of the seven components listed in LRA Table 4.3.1-1 will be managed by the Fatigue Monitoring Program (LRA Section B.3.2) for the period of extended operation.

The applicant also stated that the original ASME Code analysis of the reactor vessel also included fatigue analyses of the feedwater nozzles and the control rod drive (CRD) hydraulic system return line nozzles. After several years of operation, these nozzles were found to be susceptible to cracking caused by a number of factors, including rapid thermal cycling. The CRD hydraulic system return line nozzles were therefore capped and removed from service. As such, they are no longer susceptible to rapid thermal cycling. A re-analysis was performed on the feedwater nozzles and modifications were implemented to reduce or eliminate the effects of the high thermal cycling, based on generic BWROG guidance.

Based on its evaluation, the applicant concluded that, for some components, the fatigue analyses of the reactor vessel will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), or that for the remaining vessel components, the effects of aging will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.1.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.2, pertaining to the fatigue analysis of reactor vessel components. The CLB fatigue analyses of components associated with the reactor vessels were identified as TLAAs, in accordance with the provisions of 10 CFR 54.3(a) and the components listed in the appropriate tables in the GALL Report. The applicant listed the bounding CUFs associated with these TLAAs and indicated that the CUFs for four vessel components would exceed the ASME Code Section III Class 1 limiting value of 1.0 during the period of extended operation. The applicant, therefore, committed to monitor the fatigue of these vessel components as part of the Fatigue Monitoring Program, which provides for monitoring fatigue stress cycles to ensure that the CUF limit of 1.0 is not exceeded. The staff found this acceptable and concurred with the applicant that the effects of aging of the reactor vessel components for BFN will be adequately managed with the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii) The staff also found acceptable that, for those components where the CUF did not exceed 1.0, the fatigue analyses were projected to remain valid to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the reactor vessel fatigue TLAAs is provided in LRA Section A.3.2.1. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.1.

4.3.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of reactor vessel fatigue analyses in LRA Section A.3.2.1. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the reactor vessel fatigue TLAAs and is, therefore, acceptable.

4.3.1.4 Conclusion

The staff reviewed the applicant's TLAA on the reactor vessel fatigue analyses, as summarized in LRA Section 4.3.1, and determined that the metal fatigue assessments at Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff, therefore, concluded that the applicant's TLAA for reactor vessel fatigue analyses meets the requirements of 10 CFR 54.21(c)(1)(ii), (iii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on reactor vessel fatigue analyses for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.2 Fatigue Analysis of Reactor Vessel Internals

4.3.2.1 Summary of Technical Information in the Application

In LRA Section 4.3.2, "Fatigue Analysis of Reactor Vessel Internals," the applicant stated that the original fatigue evaluation of the reactor vessel internals was performed using ASME Code Section III as a guide. The evaluation determined that the most significant fatigue loading occurs at the jet pump diffuser-to-baffle-plate weld location. The fatigue analysis of this location was the only fatigue analysis actually performed. Since this analysis was based on a number of cycles for a 40-year life, it is considered a TLAA. The calculated CUF was 0.35, less than the ASME Code Section III Class 1 allowable CUF of 1.0. Since the original fatigue analysis was based on a 40-year design life, the calculation for the jet pump diffuser-to-baffle-plate weld was projected for a 60-year life by multiplying the CUF by 1.5, which resulted in a CUF less than the ASME Code allowable of 1.0.

The applicant also stated that at Unit 3, a lower section of the core spray line was replaced, and a repair was installed to address cracking found at the location of the core spray-to-T-box weld. Fatigue calculations were performed for several components of the core spray line using ASME Code Section III as a guide, since the core spray line is not classified as an ASME Code Section III component. However, these analyses are considered as TLAAs since they were based on a 40-year life. A fatigue evaluation of the lower core spray line sectional replacement was performed, resulting in a maximum calculated CUF of 0.45, based on a 40-year design life. An explicit fatigue calculation was also performed for the T-box repair, based on a 40-year design life. The CUF was calculated to be 0.022. The fatigue calculation for the core spray-to-T-box weld repair was evaluated for a lifetime of 60 years by multiplying the 40-year CUF by 1.5, which resulted in a 60-year CUF that is less than the ASME Section III Class 1 limit of 1.0. The fatigue analysis is, therefore, acceptable for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The applicant also concluded that these results are applicable for BFN.

The applicant stated that the core spray-to-T-box weld location is also included for inspection as part of the Boiling Water Reactor Vessel Internals Program (LRA Section B.2.1.12). These inspections will be used to manage the effects of potential cracking of these welds.

For the lower core spray sectional replacement, the design life was specified as 40 years. However, since this modification was installed more than 20 years into the current licensing period, the applicant concluded that these fatigue calculations will remain valid for the period of extended operation.

Based on the revised fatigue analyses, the applicant concluded that, in accordance with 10 CFR 54.21(c)(1)(i), the fatigue analyses for the reactor internals remain valid for the period of extended operation or, in accordance with10 CFR 54.21(c)(1)(ii), the fatigue analyses have been projected to the end of the period of extended operation. The applicant also stated that, in accordance with 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) of the reactor vessel internals for the BFN units will be adequately managed for the period of extended operation.

4.3.2.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.2 pertaining to the fatigue analysis of reactor vessel internals. Based on the reported CUFs corresponding to the reported fatigue analyses, the staff concurred with the applicant that the fatigue analyses for the reactor vessel internals remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), or that the fatigue analyses have been projected to the end of the period of extended operation, in accordance with10 CFR 54.21(c)(1)(ii). The staff also found acceptable that the effects of aging on the intended function(s) of the reactor internals for BFN will be adequately managed with the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

In accordance with 10 CFR 54.21(d), the applicant’s supplement for the UFSAR regarding the fatigue analyses of reactor vessel internals is provided in LRA Section A.3.2.2. The staff reviewed this supplement and found it acceptable. It provides a reasonable summary of the information presented in LRA Section 4.3.2.

4.3.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the “programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation.” The applicant provided a UFSAR supplement summary description of the fatigue analysis of reactor vessel internals in LRA Section A.3.2.2. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the reactor vessel internals fatigue TLAAs and is, therefore, acceptable.

4.3.2.4 Conclusion

The staff reviewed the applicant’s reactor vessel internals fatigue TLAAs, as summarized in LRA Section 4.3.2, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff’s requirements throughout the period of extended operation. The staff, therefore, concluded that the applicant’s evaluation of reactor vessel internals fatigue TLAAs meets the requirements of 10 CFR 54.21(c)(1)(i) - (iii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the

TLAA on fatigue analysis of reactor vessel internals for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.3 Piping and Component Fatigue Analysis

4.3.3.1 Summary of Technical Information in the Application

In LRA Section 4.3.3, “Piping and Components Fatigue Analysis,” the applicant stated that the reactor coolant pressure boundary (RCPB) and non-RCPB piping was designed to USA Standard (USAS) B31.1. This code does not require an explicit fatigue analysis. However, the RCPB and non-RCPB piping within the scope of license renewal that is designed to USAS B31.1 requires the application of a stress reduction factor to the allowable thermal stress range if the number of full range cycles exceeds 7000.

The applicant indicated that the assumed thermal cycle count for the analyses can be approximated by the thermal cycles used in the reactor vessel fatigue analysis. These thermal cycles are listed in UFSAR Section 4.2.5. The total count of all these listed thermal cycles is fewer than 1100 over the 40-year plant life. For the 60-year extended operating period, the number of assumed operating cycles would be increased to 1650, considerably fewer than the 7000 cycle threshold in USAS B31.1. In accordance with 10 CFR 54.21(c)(1)(i), the applicant concluded that the existing piping analyses within the scope of licence renewal will remain valid for the period of extended operation.

4.3.3.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.3, pertaining to the fatigue analysis of piping and components. The applicant indicated that the RCPB and non-RCPB piping and components at BFN, within the scope of license renewal, were designed to USAS B31.1-1967. Although this Code does not require explicit fatigue analysis, it considers fatigue implicitly in the design calculations by applying a stress range reduction factor to the allowable thermal stress range, which depends on the number of design thermal expansion cycles. The staff, therefore, concurred with the applicant that qualifications of piping to this code are considered TLAAs, in accordance with the provisions of 10 CFR 54.21(c)(1).

In the application of USAS B31.1-1967, the applicant approximated the number of thermal expansion cycles over a 40-year plant life by the thermal cycles used in the reactor vessel fatigue analysis. These thermal cycles are listed in UFSAR Section 4.2.5. For a 60-year plant life, the total count of all significant full thermal cycles was determined as fewer than 1650, which is substantially less than the 7000-cycle full thermal stress range limit in USAS B31.1. The staff concurred with the applicant that an adequate margin of safety for the RCPB and non-RCPB systems will be maintained for the period of extended operation, because the projected number of thermal operating cycles to the end of the period of extended operation is fewer than the design cycle limit of 7000 cycles, and the stress range limits in the current piping calculations therefore remain valid. The staff, therefore, concurred with the applicant that the existing piping analyses, within the scope of license renewal, will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the piping and component fatigue analyses is provided in LRA Section A.3.2.3. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.3.

4.3.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of piping and component fatigue analysis in LRA Section A.3.2.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the piping and component fatigue TLAA and is, therefore, acceptable.

4.3.3.4 Conclusion

The staff reviewed the applicant's piping and component fatigue TLAA, as summarized in LRA Section 4.3.3, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff therefore concluded that the applicant's piping and component fatigue TLAA meets the requirements of 10 CFR 54.21(c)(1)(ii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the piping and component fatigue TLAA for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.4 Effects of Reactor Coolant Environment On Fatigue Life of Components and Piping (Generic Safety Issue 190)

4.3.4.1 Summary of Technical Information in the Application

In LRA Section 4.3.4, "Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)," the applicant described the actions taken to address the issue of environmentally assisted fatigue. Generic Safety Issue (GSI) 190 addresses the effects of reactor coolant environment on the fatigue life of components and piping. Although GSI 190 is resolved, SRP-LR Section 4.3.1.2 states that for licence renewal, the applicant's consideration of the effects of coolant environment on component fatigue life is an area of review.

The applicant stated that plant-specific calculations were performed for the following fatigue sensitive component locations, identified in NUREG/CR 6260 for older-vintage BWRs:

- reactor vessel shell and lower head
- reactor vessel feedwater nozzle
- reactor recirculation piping (outlet and inlet nozzles)
- core spray system (nozzle and safe end)
- residual heat removal (RHR) line Class 1 piping

- feedwater line Class 1 piping

The applicant stated that for each location listed above, detailed environmental fatigue calculations for 60 years were performed using the appropriate environmental fatigue life correction factor (F_{en}) relationships from NUREG/CR 6583 “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” for carbon and alloy steels, and the appropriate F_{en} relationships from NUREG/CR 5704 “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” for stainless steel, as appropriate for the material. These evaluations are consistent with the recommendations in SRP-LR Section 4.3.2.2 for addressing the effects of the reactor coolant environment by assessing the effects on a sample of critical components. The 60-year CUF for the reactor recirculation piping was determined as 4.181, and the 60-year CUF for the feedwater line Class 1 piping was calculated as 1.489. In accordance with 10 CFR 54.21(c)(1)(iii), the applicant stated that all necessary plant transients will be tracked using the Fatigue Monitoring Program, to ensure that CUF values will remain below 1.0 for the period of extended operation. For the locations where the CUF is expected to exceed 1.0 for the 60-year period, the applicant stated that additional fatigue analyses will be performed prior to the period of extended operation, and appropriate action will be taken if the EOL CUF values above 1.0 are projected.

4.3.4.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.4 pertaining to the effects of reactor coolant environment on the fatigue analysis of components and piping.

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, concluding that:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (Nuclear Energy Institute (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 concluded that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older-vintage BWR plant for effect of the environment on the fatigue life of the components. For each location, detailed environmental fatigue calculations were performed using the appropriate F_{en} relationships from NUREG/CR 6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” for carbon and alloy steels, and those from NUREG/CR 5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel, as appropriate for the material. These calculations showed that two locations were projected to exceed the CUF limiting value of 1.0 prior to the end of the period of extended operation. In accordance with 10 CFR 54.21(c)(1)(iii), the applicant committed to track all necessary plant transients, using the BFN Fatigue Monitoring Program, to ensure that the CUF values will remain below 1.0 for the period of extended operation. For those locations where the CUF is expected to exceed 1.0 for the 60-year period, the applicant stated that additional analyses will be performed prior to the period of extended operation, and appropriate action will be taken if the end-of-life CUF values are projected to be above 1.0.

The staff found the environmental fatigue effects assessment acceptable, since this evaluation is consistent with the recommendations in SRP-LR Section 4.3.2.2 for addressing the effects of the reactor coolant environment by assessing the effects on a sample of critical components. The staff also found acceptable the applicant's commitment to use the Fatigue Monitoring Program to assure that the CUFs at the critical locations will not exceed the limiting CUF value of 1.0 during the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

In accordance with 10 CFR 54.21(d), the applicant included a section addressing the effects of reactor coolant environment on fatigue life of components and piping (Issue 190) in LRA Section A.3.2.4. The applicant committed to include the locations that have projected CUF values greater than 1.0 in the Fatigue Monitoring Program. The staff found this supplement acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.4.

4.3.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of GSI 190 in LRA Section A.3.2.4. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on GSI 190 and is, therefore, acceptable.

4.3.4.4 Conclusion

The staff reviewed the applicant's TLAA on GSI 190, as summarized in LRA Section 4.3.4, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff therefore concluded that the applicant's TLAA for GSI 190 meets the requirements of 10 CFR 54.21(c)(1)(iiI), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on GSI 190 for the period of extended operation, as required by 10 CFR 54.21(d).

4.4 <u>Environmental Qualification</u>

The 10 CFR 50.49 Environmental Qualification (EQ) Program has been identified as a TLAA for the purposes of license renewal. The TLAA of EQ electrical components includes all long-lived, passive and active electrical and instrumentation and controls (I&C) components that are important to safety and located in a harsh environment. The harsh environments of the plant are those areas that are subjected to the environmental effects of a LOCA or a high-energy line break (HELB). The EQ equipment comprises SR and Q-list equipment; nonsafety-related (NSR) equipment, the failure of which could prevent satisfactory accomplishment of any SR function; and necessary post-accident monitoring equipment.

As required by 10 CFR54.21(c)(1), the applicant must provide a list of EQ TLAAs in the LRA. The applicant shall demonstrate that one of the following is true for each type of EQ equipment: (1) the analyses remain valid for the period of extended operation; (2) the analyses have been projected to the end of the period of extended operation; or (3) the effect of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

The EQ Program for Units 2 and 3 was established to verify that all plant equipment within the scope of 10 CFR 50.49 is qualified for its application and meets its specified performance requirements when subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life. The EQ Program for Unit 1 will be established to ensure compliance with 10 CFR 50.49. The EQ Program complies with the requirements of 10 CFR 50.49(e)(5) for aging considerations that affect functionality and make provisions to replace the components or establish ongoing qualification when the demonstrated qualified life has expired. The EQ-related equipment is identified in a controlled equipment data base with a qualification binder that is maintained with records on performance specifications, electrical characteristics, and environmental conditions.

The EQ Program manages thermal, radiation and cyclic aging as applicable for all electrical components within the scope of 10 CFR 50.49. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during and after a DBE after experiencing the effects of in-service aging.

The applicant chose Option (iii) of 10 CFR 54.21(c)(1) in its TLAA evaluation to demonstrate that aging effects of the EQ equipment identified in this TLAA will be managed during the period of extended operation by the EQ Program activities. Maintaining qualification through the extended license renewal period requires that existing EQ evaluations be reanalyzed. A summary of the applicant’s application of these 10 CFR 50.49(f) methodologies to the EQ evaluations for the period of extended operations follows:

> <u>Analytical Methods</u> - The analytical models used in the re-analysis of an aging evaluation are the same as those applied during the initial qualification. The Arrhenius methodology is an acceptable thermal model for performing an aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (i.e., normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of

establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (i.e., 60 years/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. Cyclical aging will be reevaluated for those components subject to this effect.

Data Collection and Reduction Methods - Reducing excess conservatism in the service conditions used in the aging evaluation is one method that can be used in a re-analysis. Evaluations based on actual plant temperature data will, in certain cases, yield desired results for extended service life. Should the applicant opt to use this approach, plant temperature data can be obtained in several ways, including plant monitors, measurements taken by plant personnel, and temperature sensors on various plant equipment. Similar methods of reducing excess conservatism in the component service conditions may be also be used for radiation and cyclical aging.

Underlying Assumptions - Environmental excursions identified during plant operation or maintenance activities that could affect the qualification of an EQ component will be evaluated. Should unexpected adverse conditions be identified, the affected EQ component is evaluated and appropriate corrective actions taken, which may include changes to the qualification basis and conclusions reached, or restructuring of the affected component's EQ requirements.

Acceptance Criteria and Corrective Actions - If the qualification cannot be extended by re-analysis using the above methodologies, the component will be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid.

The applicant stated that the 10 CFR 50.49 EQ Program is consistent with the guidance provided for resolution in the NRC Regulatory Issue Summary 2003-09, "Environmental Qualification of Low-Voltage Instrumentation and Control Cables." The regulatory issue summary states:

> For license renewal, a re-analysis (based on the Arrhenius methodology) to extend the life of the cables by using the available margin based on a knowledge of the actual operating environment compared to the qualification environment, coupled with observations of the condition of the cables during walk-downs, was found to be an acceptable approach. Monitoring I&C cable condition could provide the basis for extending cable life.

The EQ Program allows re-analysis for maintaining qualification using the methods described above. In addition, the EQ Program has the following procedural requirements in place to monitor and track aging effects.

- Detecting degradation of materials or equipment performance by requiring preventive maintenance and periodic surveillance.
- Failure trend evaluations related to equipment and environments.
- Notification of environmental excursions and subsequent evaluation of components.
- Review of licensing, industry, and other generic industry operating experience.

4.4.2 Staff Evaluation

A site-wide EQ Program required by 10 CFR 50.49 has been developed for BFN, and implemented on Units 2 and 3, and it is expected to be implemented on Unit 1 to ensure compliance with 10 CFR 50.49. This item is discussed in SER Section 2.6.1.4.

The staff's review of LRA Section 4.4 identified areas in which additional information was necessary to complete the review of the EQ evaluation. The applicant responded to the staff's RAI as discussed below.

In RAI 4.4-2, dated November 4, 2004, the staff stated that the provisions of 10 CFR 50, Appendix A, General Design Criteria (GDC) 4 require that all equipment (electrical and mechanical) related to safety be designed to accommodate the environmental effects of postulated accidents. Similarly, Standard Review Plan (SRP) 3.11 (NUREG-0800) applies equally to mechanical and electrical equipment. Therefore, the staff requested the applicant to provide a discussion of the materials for mechanical equipment in the LRA that are required to be evaluated as an EQ TLAA that are sensitive to environmental effects (e.g., seals, gaskets, lubricants, fluids for hydraulic systems, diaphragms, and wear cycle aging from lubricant deterioration) and the aging analyses that will be, or have been, conducted to satisfy the requirements of 10 CFR 54.21(c)(1) for the period of extended operation.

In its response, by letter December 20, 2004, the applicant stated that BFN was licensed before the establishment of NRC GDC-4, "Environmental and Dynamic Effects of Design Basis," and NUREG-0800. Consequently, neither GDC-4 nor SRP 3.11 are part of BFN's CLB. Therefore, the applicant does not have a formal mechanical equipment qualification program. As part of the application review process, the applicant performed searches of Industry Guidance (SRP-LR and NEI 95-10), the UFSAR, the Operating Licenses and License Conditions, Technical Specifications, Technical Requirements Manuals, and Licensing Basis Program Documents such as In-Service Inspection and EQ for possible TLAA's. For the type of mechanical equipment described above, the only TLAA found was "Dose to Seal Rings for the High Pressure Coolant Injection and Reactor Core Isolation Cooling Containment Isolation Check Valves," SER Section 4.7.3. On the basis of its review, the staff found that the applicant had adequately addressed the concern and the issue is resolved.

In RAI 4.4-1, dated November 4, 2004, the staff requested the applicant to provide a list of components covered under EQ TLAA. In its response, by letter December, 9, 2004, the applicant provided the list of components covered under the EQ TLAA. On the basis of its review, the staff found that the applicant had adequately addressed the concern and the issue is closed.

The staff reviewed the information in LRA Section 4.4 to determine whether the applicant demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed through its existing EQ Program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

The applicant's program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49. Qualified life is determined for equipment within the scope of the EQ Program and appropriate actions, replacement or refurbishment are taken prior to or at the end of qualified life of the equipment so that aging limits or acceptable margins are not exceeded.

On the basis of its review, the staff concluded that the applicant had addressed the issues associated with GSI-168. The applicant will continue to manage the effects of aging through the EQ Program for the period of extended operation. The staff found that the applicant had satisfactorily addressed GSI-168 for license renewal, as required by 10 CFR 54.21(c)(1)(iii). The staff issued Regulatory Issue Summary (RIS) 2003-09 on May 2, 2003, to inform addressees of the results of the technical assessment of GSI-168. This RIS requires no action on the part of the addressees. Therefore, the staff considers GSI-168 issue to be resolved.

4.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement 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.” The applicant provided a UFSAR supplement summary description of EQ in LRA A.3.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on EQ and is, therefore, acceptable.

4.4.4 Conclusion

On the basis of its review, the staff concluded that the applicant demonstrated that the effect of aging on the intended function(s) of electrical and I&C components will be adequately managed for the period of extended operation by the existing EQ Program as required by 10 CFR 54.21(c)(1)(iii).

4.5 Loss of Prestress in Concrete Containment Tendons

The BFN containments do not have prestressed tendons. As such, this topic is not a TLAA applicable for BFN.

4.6 Primary Containment Fatigue

Cyclic loads acting on the primary containment and the attached piping and components include reactor building interior temperature variation during the heatup and cooldown of the RCS, a postulated LOCA, annual outdoor temperature variations, thermal loads on containment penetrations due to high-energy piping lines (such as steam and feedwater lines), seismic loads, and pressurization due to periodic Type A integrated leak-rate tests.

Metal containment penetration sleeves (including dissimilar metal welds) and penetration bellows may be designed in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. 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 of the containment sleeves and bellows will be adequately managed for the period of extended operation.

In LRA Section 4.6, the applicant referenced UFSAR Section C.5.1, which states that the primary containment vessels for Units 1 and 2 were designed in accordance with the ASME Code Section III 1965 Edition with Addenda up through Winter 1966. The primary containment vessel for Unit 3 was designed in accordance with the ASME Code Section III1965 Edition with Addenda up through Summer 1967. Subsequently, while performing large-scale testing for the Mark III containment system and in-plant testing for the Mark I containment system, new hydrodynamic loads were identified for the suppression chamber (also referred to as the torus), that were not included in the original structural analyses. These additional loads result from blowdown into the suppression chamber during a postulated LOCA, and from main steam relief valve operation during plant transients. The results of structural analyses for BFN under these effects were reported in the BFN Torus Integrity Long-Term Program Plant Unique Analysis Report (PUAR). This program is described in UFSAR Section C.5.3. The applicant indicated that modifications of the suppression chamber and the suppression chamber vents, including the vent headers and downcomers, were required in order to re-establish the original design safety margins. The safety margins for these components were determined based on the allowable stresses stated in Subsection NE of the 1977 ASME Boiler and Pressure Vessel Code, Section III, including Summer 1977 Addenda.

As part of the review of the Torus Integrity Long-term Program PUAR, the applicant identified the following fatigue analyses as TLAAs:

- fatigue of the torus, vents, and downcomers
- fatigue of torus-attached piping and safety relief valve discharge lines
- fatigue of vent line and process penetration bellows

In analyzing and determining the disposition of these TLAAs for the period of extended operation, the applicant applied the following criteria:

1. The applicant stated that locations with a 40-year CUF of 0.666 are not considered as having adequate analytical or event margin when linearly extrapolated to 60 years. A CUF limit of 0.4 was chosen as providing this margin. Disposition option 10 CFR 54.21(c)(1)(i) was therefore applied to locations with a calculated 40-year CUF less than 0.4.
2. For locations where the 40-year CUF is greater than 0.4, the applicant stated that fatigue will be managed by the Fatigue Monitoring Program described in LRA Section B.3.2. Disposition option 10 CFR 54.21(c)(1)(iii) will, therefore, be applied to these locations.

4.6.1 Fatigue of Suppression Chamber, Vents, and Downcomers

4.6.1.1 Summary of Technical Information in the Application

The applicant stated that the BFN Torus Integrity PUAR includes fatigue analyses of the torus and torus vents, including the vent headers and downcomers. These analyses assumed a limited number of main steam safety relief valve (SRV) actuations and are, therefore, TLAAs.

Based on recorded plant data extrapolated to 40 years, the BFN Torus Integrity PUAR assumed 500 SRV actuations during 40 years of normal operations and the contribution from the postulated worst-case LOCA. The worst-location and the corresponding fatigue CUFs were determined as follows:

- 0.681, at the intersection of the vent headers with the downcomers
- 0.373, at the downcomer/tiebar intersection
- 0.37, for the torus restraint snubbers

Since only the SRV loads contribute to fatigue during normal operation, normal operation may continue so long as the CUF contribution from SRV actuations has not exceeded 1.0 minus the CUF contribution expected from the postulated worst-case LOCA phenomena.

The applicant indicated that, based on operating experience, the total number of SRV actuations is not expected to exceed 500 actuations for any unit during the period of extended operation. This expectation is based on an estimate of the total number of SRV actuations expected for each unit until the end of the period of extended operation. The applicant described the methodology used for estimating the total number of SRV actuations. It was based on estimating the number of SRV actuations from the start up of each unit through August 2003, an estimate of the number of valve actuations expected for the remainder of the current licensing term and for the requested period of extended operation.

The applicant stated that, based on this methodology, the number of SRV actuations from the startup of each unit through August 2003 was estimated to be 146 actuations for Unit 1, 254 actuations for Unit 2 (worst case), and 188 actuations for Unit 3. (These estimates included both planned and unplanned SRV actuations.) The estimated total number of SRV actuations from August 2003 until the end of the period of extended operation was projected to be 239 for Unit 2. Thus, the estimated total number of SRV actuations at the end of the period of extended operation for Unit 2 is 493. This is the worst-case estimate of the total number of SRV actuations expected at the end of the period of extended operation. Thus, the assumed number of 500 SRV actuations for the three units is considered to be conservative.

To ensure that corrective actions are taken before any CUF approaches 1.0, the applicant indicated that, in accordance with 10 CFR 54.3(c)(1)(iii), the applicant will manage the high CUF locations for the period of extended operation by monitoring the SRV actuations using the Fatigue Monitoring Program.

4.6.1.2 Staff Evaluation

The staff reviewed the LRA regarding the fatigue TLAAs of the torus, vents and downcomers. The staff also reviewed the applicant's disposition of these TLAAs and found it acceptable because it specified the threshold limit of CUF equals 0.4 for 40 years of operation as a criterion for determining if the fatigue analyses performed under the PUAR will remain valid for the period of extended operation. The staff concurred with the applicant that this criterion will provide additional analytical or event margin over the minimum CUF value of 0.666 for the period of extended operation. Those locations, by not exceeding the threshold criterion, will therefore remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). In accordance with 10 CFR 54.21(c)(1)(iii), for locations where the CUF exceeds the criterion above, the staff found the applicant's commitment to manage the effects of fatigue for the period of extended operation with the Fatigue Monitoring Program acceptable because it will provide assurance that the monitored CUF at a location will not exceed the ASME Code Section III CUF limiting value of 1.0; or, if the CUF is projected to exceed this limit, the applicant committed to take appropriate corrective action to assure that this limit will not be exceeded, as stated in LRA Section 4.6, in accordance with the Fatigue Monitoring Program. As described in LRA Section B.3.2, the Fatigue Monitoring Program will include an enhancement to monitor the fatigue of the torus and torus vents, and the vent headers and downcomers, using an EPRI-licensed cycle counting and fatigue usage tracking computer program. The applicant also committed to implement this enhancement prior to the period of extended operation.

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSARs regarding the suppression chamber, vents, and downcomers fatigue TLAAs is provided in LRA Section A.3.4 "Containment Fatigue." The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.6.1.

4.6.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of metal fatigue analyses of suppression chamber, vents, and downcomers in LRA Section A.3.4.

4.6.1.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAAs of suppression chamber, vents, and downcomers and is, therefore, acceptable.

4.6.2 Fatigue of Torus Attached Pipe and Safety Relief Valve Discharge Lines

4.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.6.2, the applicant stated that there are thirteen Target Rock dual-mode MSRVs to allow blowdown from the main steam piping in the drywell to the suppression pool via individual discharge lines passing through the main vents. These lines enter the suppression chamber through penetrations in the suppression chamber vent header and the steam is discharged to the suppression pool water through T-quenchers attached to the ends of the lines. There are, in addition, a number of other external piping systems attached to the suppression chamber shell.

The torus integrity PUAR indicates that an evaluation of the fatigue effects of Mark I containment cyclic "new loads" on main steam relief valve discharge lines internal to the suppression chamber and on torus-attached piping external to the suppression chamber was performed using a program developed by the Mark I Owners Group.

The fatigue analyses assumed 500 SRV actuations for a 40-year plant lifetime, and included the effects of both mechanical and thermal expansion load cycling. These analyses are, therefore TLAAs. The analyses concluded that the worst location on the main steam safety relief valve (MSRV) discharge lines would have a fatigue CUF of less than 0.35 at the end of 40 years of operation. The analyses also concluded that the worst location on the torus attached piping would have a fatigue CUF of less than 0.103 at the end of 40 years of operation. The applicant concluded that, for the MSRV discharge lines and T-quenchers, the MSRV discharge line penetrations, the torus attached piping systems, and the associated penetration locations, the predicted 60-year CUF will, therefore be less than 0.666 (worst-case CUF is 0.35 x 60/40 = 0.53). The applicant thus concluded that the MSRV discharge lines and the torus-attached piping fatigue analyses will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.2.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.6.2 regarding the fatigue TLAAs of the torus attached piping and the SRV discharge lines. The staff reviewed the applicant's disposition of these TLAAs and found it acceptable because the applicant selected a threshold limit of CUF equals 0.4 for 40 years of operation as a criterion for determining whether the fatigue analyses performed under the PUARs will remain valid for the period of extended operation. Based on this criterion, the staff concurred with the applicant's disposition of these TLAAs, since it demonstrated that the highest 40-year CUFs will not exceed the threshold limit of 0.40. These locations will therefore remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSARs regarding the fatigue TLAAs of the torus attached piping and the SRV discharge lines is provided as part of LRA Section A.3.4. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.6.2.

4.6.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation." The applicant provided a UFSAR supplement summary description of fatigue of torus attached pipe and SRV discharge lines in LRA Section A.3.4.

4.6.2.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAA of torus attached pipe and SRV discharge lines and is, therefore, acceptable.

4.6.3 Fatigue of Vent Line and Process Penetration Bellows

4.6.3.1 Summary of Technical Information in the Application

The applicant stated in LRA Section 4.6.3 that the torus vent line bellows are flexible expansion joints allowing movement of the main vent pipes through the torus wall without developing significant interaction loads, and maintaining the required pressure boundary. The analysis of the suppression chamber bellows is described in the PUAR and was performed in accordance with Standards of the Expansion Joint Manufacturers Association, Inc. The design life of the bellows is stated in UFSAR Section C.5.2 as 7000 thermal cycles over the 40-year life for the plant and the fatigue analyses are, therefore, TLAAs.

Containment pipe penetrations that must accommodate pipe thermal movement also have expansion bellows. Containment process piping expansion joints between the drywell shell penetrations and process piping are the only ones subject to significant thermal expansion and contraction. The design life of these bellows is also stated as 7000 operating thermal cycles over the design life at containment normal, test, and limiting design pressures throughout the 40-year life for the plant and are, therefore, TLAAs.

For the suppression chamber vent line bellows and the containment penetration bellows, thermal cycles are imposed by the thermal expansion cycles experienced by the attached piping. The assumed thermal cycle count for the analyses used in the codes associated with the piping and components can be conservatively approximated by the full thermal cycles (not including power reductions) used in the reactor vessel fatigue analysis listed in UFSAR Section 4.2.5. The applicant stated that the total count of all full thermal cycles (not including power reductions) is less than 1100 for a 40-year plant life. For the 60-year plant life, the number of thermal cycles for piping analyses would be proportionally increased to less than 1650, which is less than 25 percent of the 7000-cycle design life.

Since the suppression chamber bellows and the containment penetration bellows metal fatigue analyses have a large design fatigue life margin, the applicant concluded that the analyses will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.6.3 regarding the metal fatigue TLAAs of the vent line bellows and the containment process piping penetration bellows. The staff concurred with the applicant’s disposition of this TLAA and found it acceptable because it demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the number of full thermal cycles expected by the end of the period of extended operation will not exceed the 7000-cycle design-life of these bellows.

In accordance with 10 CFR 54.21(d), the applicant’s supplement for the UFSAR regarding the metal fatigue TLAAs of the vent line and process penetration bellows is provided in LRA Section A.3.4. The staff reviewed this supplement and found it acceptable. It provides a reasonable summary of the information presented in LRA Section 4.6.3.

4.6.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the “programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation.” The applicant provided a UFSAR supplement summary description of metal fatigue analyses of vent line and process penetration bellows in LRA Section A.3.4.

4.6.3.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAAs of vent line and process penetration bellows and is, therefore, acceptable.

4.7 <u>Other Plant-Specific Analyses</u>

In LRA Section 4.7, the applicant provided its evaluation of plant-specific TLAAs. The TLAAs evaluated include the following:

- reactor building crane load cycles
- corrosion – flow reduction
- dose to seal rings for the high pressure coolant injection and reactor core isolation cooling containment isolation check valves
- radiation degradation of drywell expansion gap foam
- corrosion – minimum wall thickness
- irradiation assisted stress corrosion cracking of reactor vessel internals
- stress relaxation of core plate hold-down bolts
- emergency equipment cooling water weld flaw evaluation

4.7.1 Reactor Building Crane Load Cycles

4.7.1.1 Summary of Technical Information in the Application

The applicant stated in Section 4.7.1 that the 125-ton reactor building overhead crane serves three reactor units and includes a 5-ton auxiliary load hoist. The crane is designed to meet the design loading requirements of the Crane Manufacturers Association of America (CMAA) Specification 70. For cyclic loading, CMAA 70 specifies that a crane classified as Service Class A1 is limited to 100,000 loading cycles over the design life. The applicant's analysis identifies that the total number of expected cycles for this crane over the entire life including construction, the 60-years of operation for all three units, and the decommissioning, has been conservatively estimated at less than 21,00 loading cycles. Of these, less than 1000 lifts are expected to be more than 90 percent of the rated capacity. The applicant concluded that the analysis of the 125-ton reactor building crane qualifies the passive structural components for extended life in accordance with CMAA 70 Service Class A1 requirements.

4.7.1.2 Staff Evaluation

During its review of the applicant's analysis the staff determined that additional information was needed to complete its review. The staff identified that TVA letter dated September 28, 1982, in response to NUREG-0612, stated that the structural and rotating parts of the crane were designed for infinite life. In RAI 4.7.1-1, the applicant was requested to clarify if infinite life is still valid or to explain the derivation of the total number of loading cycles estimated. In this RAI, the applicant was also requested to explain the difference between the 21,000 cycles estimated in

LRA Section 4.7.1 and the 7,500 cycles estimated in LRA Section B.2.1.20. Further, the applicant was requested to clarify if additional loading cycles caused by vibration during crane operation are considered in the analysis or are the basis for not including loading cycles induced by vibration. By letter dated January 12, 2005, the applicant explained that its letter dated September 28, 1982, is based on an endurance limit of 40 percent of the tensile strength which, although reasonable, is not in accordance with CMMA 70; therefore, the results of the evaluation for license renewal supercede the September 28, 1982, results provided to the NRC. The applicant also clarified that the 7,500 lifts are full-load equivalent cycles, and that the estimated load lifts are less than 1,000 near-rated lifts, less than 10,000 moderate-load lifts, and less than 10,000 light-load lifts. In regard to vibration, the applicant's response clarified that a review of operating experience indicates that vibration in the structural components has not been noticed or reported for the reactor building crane. The applicant identified that non-structural vibration and wear issues have been reported. For example, motor generator vibration has been reported, measured, and promptly corrected. The staff determined that the applicant's response satisfactorily answers the staff's technical concerns, and all items related to RAI 4.7.1-1 are resolved.

Based on its review of the applicant's analysis included in the LRA and additional clarifications provided by the applicant in response to RAI 4.7.1-1, the staff concurred with the applicant that the reactor building crane has been evaluated and is qualified for the period of extended operation. The crane is qualified for a 100,000-cycle design life, which exceeds the estimated load cycles for the life of the crane including life extension. Hence counting actual load cycle is is not required for the reactor building crane because estimated load cycles are well below the limits for the crane established by CMAA 70. Therefore, fatigue life is not significant to the operation of this equipment, and the analysis is valid for the period of extended operation. The applicant provided a satisfactory validation of 10 CFR 54.21(c)(1)(i). The staff also reviewed the UFSAR Supplement A.3.5.1 and determined that the UFSAR Supplement includes an appropriate summary description of the reactor building crane load cycles TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of reactor building crane load cycles in LRA Section A.3.5.1. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reactor building crane load cycles and is, therefore, acceptable.

4.7.1.4 Conclusion

On the basis of its review, the staff concluded that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i) that the analyses remain valid for the reactor building crane load cycles TLAA. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the reactor building crane load cycles TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21 (c)(1).

4.7.2 Corrosion – Flow Reduction

LRA Section 4.7.2 originally considered a design calculation that addresses concerns whether the flow reduction due to corrosion in carbon steel piping used in raw water systems is a TLAA. In a letter dated June 15, 2005, the applicant provided additional information. The functional basis for determining the acceptability is based on periodic flow testing as described in the Technical Instruction 0-TI-171 RHRSW Sump Pump Flow Test, Surveillance Instruction 0-SI-4.5.C.1(4) EECW System Annual Flow Rate Test, Surveillance Instruction 1/2/3-SI-4.5.C.1(3) RHRSW Pump and Header Operability and Flow Test, and Surveillance Instructions 0-SI-4.11.B.1.g for Fire Protection Piping. Based on its further review, the applicant determined that the calculation should not be considered to be a TLAA; therefore, this section is deleted from the application.

4.7.3 Dose to Seal Rings for the High Pressure Coolant Injection and Reactor Core Isolation Cooling Containment Isolation Check Valves

Although this TLAA was included in the initial LRA, the applicant by its letter dated June 9, 2005, made a review of the safety determination per 10 CFR 54.3, and stated as follows:

> LRA Section 4.7.3 originally considered a design calculation that determines the dose to seal rings on the high-pressure coolant injection system and reactor core isolation cooling system testable check valves to be a TLAA. After further review, the applicant determined that the calculation is used to validate the seal design, but is not relied on to make a safety determination. The ability of the valve to perform its safety function is verified by Type C leak testing performed per BFN Technical Instruction 0-TI-360, "Containment Leak Rate Programs." Based on this further review, the applicant determined that the calculation should not be considered to be a TLAA, and that Section 4.7.3, “Dose To Seal Rings For The High Pressure Coolant Injection And Reactor Core Isolation Cooling Containment Isolation Check Valves,” should be deleted from the LRA.

The staff concurred with the applicant’s assessment that this is not a TLAA and its determination not to include it in the safety evaluation.

4.7.4 Radiation Degradation of Drywell Expansion Gap Foam

4.7.4.1 Summary of Technical Information in the Application

In LRA Section 4.7.4, the applicant stated that the steel drywell shell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling of the drywell over areas where the concrete backs up the steel shell. The drywell is separated from the reinforced concrete by a gap of approximately 2 inches and filled with polyurethane foam.

4.7.4.2 Staff Evaluation

In RAI 4.7.4-1, dated December 10, 2004, the staff stated that LRA Table 3.5.2.2 lists the aging management review (AMR) results of expansion joint (elastomer, polyurethane foam) as a TLAA and refers the TLAA to LRA Section 4.7. LRA Section 4.7.4, “Radiation Degradation of Drywell Expansion Gap Foam,” states that an analysis of the effect of dose on the foam showed that the material properties will remain within the limits assumed by the original design analysis for the additional 20 years of extended operation. Therefore, the staff requested the applicant to provide a more detailed discussion of the analysis,[1] including a discussion of the method and assumptions adopted in the analysis, the type of data extrapolation applied, and the quantitative results obtained to justify the applicant's assertion that the requirements of 10 CFR 54.21(c)(1)(i) are fully met.

In its response, by letter dated January 31, 2005, the applicant stated that:

> The TLAA analysis determines that the total dose to the polyurethane foam located between the drywell steel and the reactor building concrete will result in a total dose of less than 1.0E8 rads. The material properties of the polyurethane foam will remain within the limits assumed by the original analysis for a total dose of less than 1.0 E08 rads.
>
> The analysis model consists of the standard geometry sphere with a steel clad of 0.825 inches (drywell steel thickness). The radius of the sphere is 33.5 feet. Computer code QAD-P5Z, which is a point kernel variation of QAD-P5F, was used to determine dose and/or exposure rates. The computer code PARINT integrated the dose rates over time. The principle gamma source from normal operation is N-16; therefore the photon spectrum for normal operation is for N-16 with an arbitrary 1 Ci activity as input. The resultant dose rate was then scaled to the appropriate power level. The STP computer code determined the time dependent photon spectra. STP is the standard TVAN computer code for source term development. Gamma and neutron attenuation are considered.
>
> Actual power conditions are utilized in the TLAA analysis. This applies for roughly the first 25% of plant life during which time each unit was down for a significant amount of time. For conservatism, it is assumed that EPU starts October 24, 2003, even though Unit 1 has yet to be restarted. Prior to October 24, 2003, Units 2 and 3 are at 105% (uprate) conditions. For an additional conservatism, Permali neutron shielding has not been included in the TLAA analysis.
>
> The foam will only receive the significant dose from the drywell. The drywell is surrounded by a minimum of 5 feet of concrete. It is clear that the drywell sources will have a greater impact than any sources in the reactor building. The reactor building source impact will be negligible compared to the drywell.

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[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

> The maximum dose for 60 year operation at EPU conditions without Permali neutron shielding occurs for Unit 2 and is 9.92E+07 which is less than a total dose of 1.0E08 rads used in the original analysis. Therefore, the material properties of the polyurethane foam will remain within the limits assumed by the original analysis.

In addition, the staff requested the applicant to provide tests or other research publication based justification for making the following assertion that: "The material properties of the polyurethane foam will remain within the limits assumed by the original analysis for a total dose of less than 1.0 E08 rads."

In its letter dated May 24, 2005, the applicant responded with the following:

> The basis for asserting that the polyurethane foam will maintain its material properties when exposed to radiation dosage is BFN UFSAR Section 5.2.3.2 which states in part "… Irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to 10^8R." This is in accordance with BFN's current licensing basis. Additionally, this same information is presented in Section 4.7.4, "Summary Description," of the LRA.

The staff found that the applicant provided adequate engineering analysis results and related material test data to fully resolve the RAI. Therefore, the staff's concern described in RAI 4.7.4-1 is resolved.

4.7.4.3 UFSAR Supplement

UFSAR Section 5.2.3.2 states that irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to 1.0×10^8 rads. This test-based material performance data, in conjunction with the above-discussed TLAA analysis results, form the basis for the staff's determination that the effects of aging due to radiation degradation of drywell expansion gap foam will be adequately managed. The applicant provided UFSAR supplement summary description of drywell expansion gap foam in LRA Section A.3.5.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA in LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam."

4.7.4.4 Conclusion

The staff reviewed the applicant's TLAA on radiation degradation of drywell expansion gap foam, as summarized in LRA Section 4.7.4, including information submitted in response to the staff's RAI and determined that the effects of aging due to radiation degradation of drywell expansion gap foam will be adequately managed. Therefore, the staff concluded that the applicant has demonstrated that the effects of aging due to radiation degradation of drywell expansion gap foam 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(c)(1)(iii).

4.7.5 Corrosion – Minimum Wall Thickness

Although this TLAA was included in the initial LRA, the applicant by its letter dated June 15, 2005, made a review of the safety determination per 10 CFR 54.3, and stated as follows:

LRA Section 4.7.5 originally considered a design calculation that shows corrosion/erosion resulting in decreasing pipe wall thickness to be a TLAA. The functional basis for ensuring the wall thickness acceptability is accomplished by inspection, testing, and monitoring activities performed by plant procedures implementing SPP-9.7, Corrosion Control Program. Based on its further review, the applicant determined that the calculation should not be considered a TLAA; therefore, this section is deleted from the application.

The staff concurred with the applicant's assessment that this is not a TLAA and with its determination not to include in the safety evaluation.

4.7.6 Irradiation Assisted Stress Corrosion Cracking of Reactor Vessel Internals

4.7.6.1 Summary of Technical Information in the Application

The applicant in LRA Section 4.7.6 provided the following description for the TLAA on IASCC in austenitic stainless steel RV internal components:

> Austenitic stainless steel reactor internal components exposed to neutron fluence greater than 5×10^{20} n/cm^2 (E > 1 MeV) are considered susceptible to Irradiation Assisted Stress Corrosion Cracking (IASCC) in the BWR environment. As described in the SER (ML003776810, 12/07/2000) to BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," IASCC of reactor internals is considered a TLAA. Fluence calculations have been performed for the RV and internals. Four components have been identified as being susceptible to IASCC for the period of extended operation: (1) Top Guide; (2) Shroud; (3) Core Plate and (4) In-core Instrumentation Dry Tubes and Guide Tubes.
>
> The top guide, shroud, core plate and in-core instrumentation dry tubes and guide tubes are considered susceptible to IASCC. The aging effect associated with IASCC, crack initiation and growth, will require aging management. Three components, top guide, shroud and incore instrumentation dry tubes and guide tubes, have been evaluated by the BWRVIP, as described in the Inspection and Evaluation Guidelines for each component: BWRVIP-26 (Top Guide), BWRVIP-76 (Shroud), and BWRVIP-47 (in-core instrumentation dry tubes and guide tubes). BFN implements the BWRVIP recommendations, as described in B.2.1.5 (Chemistry Control Program) and B.2.1.12 (BWR Vessel Internals Program). The core plate has been determined to be susceptible to IASCC and this is considered a plant-specific TLAA. BFN will manage this TLAA with two aging management programs: Chemistry Control Program (B.2.1.5) and BWR Vessel Internals Program (B.2.1.12). For the period of extended operation, the BWR Vessel Internals Program will perform inspections of the core plate in the regions of the highest fluence.

4.7.6.2 Staff Evaluation

The staff reviewed the information provided by the applicant in the LRA and determined that the austenitic stainless steel materials that are located in the following RV internal components are exposed to neutron fluence greater than 5×10^{20} n/cm^2 (E > 1 MeV) and are considered susceptible to IASCC in the BWR environment: (1) top guide, (2) shroud, (3) core plate, and (4) in-core instrumentation dry tubes and guide tubes. The applicant stated that the aging effects due to IASCC in the aforementioned components are managed by two aging management programs (AMPs): (1) Chemistry Control Program, and (2) Boiling Water Reactor Vessel Internals Program. The Boiling Water Reactor Vessel Internals Program in turn addresses several BWRVIP inspection programs that are designed for various RV internal components. In addition, the Boiling Water Reactor Vessel Internals Program invokes the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program. The applicant claimed that implementation of these AMPs provides reasonable assurance that the aging effects due to IASCC will be managed so that the systems and components within the scope of this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation. The applicant committed to implement the relevant BWRVIP programs to manage aging effects that are associated with each of the aforementioned components. The staff, in the following paragraphs, discusses the effectiveness of these AMPs in managing the aging effect due to IASCC in each of the aforementioned components.

Top Guide - In addition to the implementation of the Chemistry Control Program, and the Boiling Water Reactor Vessel Internals Program, the applicant committed to invoke the inspection guidelines that are specified in the BWRVIP-26, “Boiling Water Reactor Top Guide Inspection and Flaw Evaluation Guidelines,” which has been approved by the staff. The implementation of these additional guidelines and the AMPs is consistent with the GALL AMP XI.M9. The staff found that, by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the top guide can be controlled.

In RAI B.2.1.12-1(A), dated December 1, 2004, the staff indicated that the BWRVIP-26 report lists 5×10^{20} n/cm^2 (E > 1.0 MeV) as the threshold fluence beyond which components may be susceptible to IASCC. According to the generic analysis in BWRVIP-26, the location on the top guide that will see a fluence equal to or greater than 5×10^{20} n/cm^2 (E > 1.0 MeV) is the grid beams. This is location 1, as identified in BWRVIP-26, Table 3-2, "Matrix of Inspection Options.” In its evaluation of the top guide assembly in BWRVIP-26, GE assumed a lower allowable stress value, acknowledging the high fluence value at this location. The conclusion of GE’s analysis, and the fact that a single failure at this location has no safety consequence, was that no inspection was necessary to manage IASCC in top guide grid beams.

The staff was concerned that multiple failures of the top guide grid beams are possible when the threshold fluence for IASCC is exceeded. According to BWRVIP-26, multiple cracks have been observed in top guide beams at Oyster Creek Nuclear Power station. In order to exclude the top guide grid beams from inspection when their fluence exceeds the threshold value, it must be demonstrated that failure of all beams that exceed the threshold fluence will not impact the safe shutdown of the reactor during normal, upset, emergency, and faulted conditions. If this cannot be demonstrated, then an inspection program to manage this aging effect to preclude loss of component intended function is required.

In its response, by letter dated January 31, 2005, the applicant indicated that LRA Section 4.7.6 considered the fluence at the top guide as a TLAA. The applicant manages this TLAA with the Chemistry Control Program and the BWRVIP. The BWRVIP implements the requirements of NRC-accepted BWRVIP-26. The NRC letter to Carl Terry, BWRVIP Chairman, dated June 10, 2003, states the following: "The staff believes that a comprehensive evaluation of the impact of IASCC and multiple failures of the top guide beams is necessary, and that an inspection program for top guide beams for all BWRs should be developed by the BWRVIP to ensure that all BWRs can meet the requirements of 10 CFR Part 54 throughout the period of extended operation." The applicant made a commitment, as part of the BWRVIP, to work to resolve these issues generically. When resolved, the applicant will follow the BWRVIP recommendations resulting from that resolution. Prior to the period of extended operation, the applicant will develop a site-specific inspection program, if necessary, to manage the effects of IASCC in the top guide.

The staff determined that the applicant was required to submit, for NRC review and approval, a site-specific AMP that addresses potential multiple failures of the top guide grid beams. The applicant, in its response dated May 25, 2005, indicated that it will perform inspections of the guide beams similar (in inspection methods, scope and frequency of inspection) to the inspections specified in the BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," for the control rod guide tube components. The applicant stated that the extent of examination and its frequency will be based on a ten percent sample of the total population, which includes all grid beam and beam-to-beam crevice slots, within 12 years and five percent of the population is to be completed within six years. The applicant stated that the program to inspect the top guide grid beams will be implemented prior to the end of the current license period. The sample locations selected for examination will be in areas that are exposed to highest neutron fluence. The staff found this response acceptable because it defines a representative population of IASCC susceptible locations, and selects locations in the top guide that are exposed to the highest neutron fluences. In addition, the proposed inspection requirements were previously accepted by the staff in the SE related to the license renewal of Peach Bottom Atomic Power Station, Units 2 and 3. The staff considered this RAI resolved.

<u>Core Shroud</u> - In addition to the implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, Chemistry Control Program, and BWR Vessel Internals Program, the applicant committed to implement the inspection guidelines of BWRVIP-76 "Boiling Water Reactor Core Shroud Inspection and Flaw Evaluation Guidelines." The staff's review of this report is not complete. The applicant proposed to evaluate the staff SER and complete SER action items. The staff requested that the applicant make a commitment to follow all the requirements and limitations that may be specified in the staff SE on the BWRVIP-76 report. The staff found that, by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of RCS water can be controlled and, thereby, the corrosion of the core shroud can be controlled. In addition, implementation of the Inservice Inspection Program mandated by ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-76, will adequately identify any cracking in a timely manner so that proper repair and other mitigation techniques can be implemented to restore the function of the core shroud. Since the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1.1-a through IV.B1.1-g, the staff found that the applicant had 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).

In RAI 4.2.4-1(B), dated December 1, 2004, the staff stated that in LRA Section 4.2.4, the applicant stated that the maximum 54 EFPY fluence at the inside surface of the core shroud is 5.34×10^{21} n/cm^2 (E > 1.0 MeV). Therefore, the staff requested that the applicant address the aging effect due to IASCC in the core shroud component.

In its response, by letter January 31, 2005, the applicant stated that the core shrouds are classified as "Category C," based on the core shroud classification criteria contained in Appendix B of the BWR Vessel Internals Program. The BWR Vessel Internals Program requires inspection of core shroud welds in accordance with "Category C" core shroud inspection requirements contained in BWRVIP-76. The staff reviewed this response and accepted it (pending the approval of the BWRVIP-76 report) because implementation of the BWR Vessel Internals Program and the Chemistry Control Program would adequately manage the aging effect due to IASCC in the core shroud components and is consistent with GALL AMP XI.M9 and XI.M2.

<u>Core Plate</u> - The applicant proposed to implement the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, Chemistry Control Program, and BWR Vessel Internals Program. The BWR Vessel Internals Program in turn invokes the inspection guidelines of the BWRVIP-25, "Boiling Water Reactor Core Plate Inspection and Flaw Evaluation Guidelines," which has been approved by the staff. The staff found that by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the core plate can be controlled. In addition, implementation of the Inservice Inspection Program mandated by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-25, will adequately identify any cracking in a timely manner so that proper repair and other mitigation techniques can be implemented to restore the function of the core plate. Since the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1.1-a through IV.B1.1-g, the staff found that the applicant had 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).

<u>In-core Instrumentation Dry Tubes and Guide Tubes</u> - In addition to the implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program, and BWR Vessel Internals Program, the applicant committed to invoke the inspection guidelines specified in BWRVIP-47, "Boiling Water Reactor Lower Plenum Inspection and Flaw Evaluation Guidelines," which has been approved by the staff. The staff found that by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the in-core instrumentation dry tubes and guide tubes can be controlled. In addition, implementation of the Inservice Inspection Program mandated by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-47, will adequately identify any cracking in a timely manner, so that proper repair and other mitigation techniques can be implemented to restore the function of the in-core instrumentation dry tubes and guide tubes. Since the implementation of these additional guidelines and AMPs is consistent with the GALL Report, the staff found 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).

4.7.6.3 UFSAR Supplement

Section LRA A.3.5.5 includes the following UFSAR Supplement summary description for the TLAA on IASCC of the RV internals.

> Austenitic stainless steel RV internal components exposed to a neutron fluence greater than 5×10^{20} n/cm ^{2}(E > 1 MeV) are considered susceptible to irradiation assisted stress corrosion cracking (IASCC) in the BWR environment. Fluence calculations have been performed for the RV and internals. Four components have been identified as being susceptible to IASCC for the period of extended operation: (1) Top Guide; (2) Shroud; (3) Core Plate and (4) In-core Instrumentation Dry Tubes and Guide Tubes. Three components (top guide, shroud and in-core instrumentation dry tubes and guide tubes) have been evaluated by the BWRVIP, as described in the Inspection and Evaluation Guidelines for each component: BWRVIP-26 (Top Guide), BWRVIP-76 (Shroud), and BWRVIP-47 (incore instrumentation dry tubes and guide tubes). BFN implements the BWRVIP recommendations. The Chemistry Program and the BWR Vessel Internals Program will be used to manage the core plate.

The applicant's UFSAR supplement summary description for the TLAA on IASCC of the RV internals appropriately describes the implementation of relevant AMPs that would enable the applicant to effectively manage this aging effect. The staff, however, requires that the applicant revise the UFSAR supplement to indicate that the inspection guidelines of the BWRVIP-25 "Boiling Water Reactor Core Plate Inspection and Flaw Evaluation Guidelines," will be implemented to effectively manage the aging effect on core plate. The applicant, in its response dated May 25, 2005, revised LRA Section A 3.5.5 of the UFSAR supplement summary description which describes that the inspection guidelines that are specified in the BWRVIP-25 report will be implemented for managing the aging effect on core plate. The staff considered this acceptable.

4.7.6.4 Conclusion

The staff reviewed the applicant's TLAA on IASCC of the RV internals, as summarized in LRA Section 4.7.6, and determined that, except for the top guide grid beams, the applicant appropriately describes that by implementing the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program and BWR Vessel Internals Program, and relevant additional BWRVIP guidelines related to RV internal components, the aging effect due to IASCC will be adequately managed for the period of extended operation. The license renewal action items related to the implementation of the BWRVIP-25, BWRVIP-26, and BWRVIP-47 guidelines are discussed in SER Section 3.1 on AMR. In addition, the staff believes that the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging due to IASCC in the RV internals with the exception of the top guide grid beams, as stated above, 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(c)(1)(iii).

4.7.7 Stress Relaxation of the Core Plate Hold-Down Bolts

4.7.7.1 Summary of Technical Information in the Application

The core plate hold-down bolts connecting the core plate to core shroud are initially preloaded during installation. These bolts are subject to stress relaxation due to thermal and irradiation effects. The loss of preload over time due to stress relaxation is considered a TLAA and evaluated accordingly. In the LRA, the applicant stated that it evaluated the loss of preload of the core plate hold-down bolts for the 40-year lifetime and concluded that all core plate hold-down bolts will maintain some preload throughout the life of the plant. This conclusion was based on an analysis of loss of preload for core plate hold-down bolts, referenced in BWRVIP-25, Appendix B, "BWR Core Plate Inspection and Flaw Evaluation Guidelines." (Reference 5). For the 60-year lifetime, the applicant estimated the expected loss of preload to be less than 20 percent. With this loss of preload, the applicant stated that the core plate will maintain sufficiently high preload at the end of the period of extended operation to prevent sliding under both normal and accident conditions. Based on this assumption, the applicant concluded that the loss of preload is acceptable for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.7.7.2 Staff Evaluation

To complete its review, the staff requested additional information regarding the data and analyses that were used to determine that the loss of preload due to stress relaxation at the end of the period of extended operation would be less than 20 percent. The staff also requested that the applicant show that the hold-down bolts would meet the required ASME Code Section III stress acceptance criteria at the end of the period of extended operation.

In RAI 4.7.7-1, dated March 3, 2005, the staff requested that the applicant demonstrate the applicability of BWRVIP-25, (Reference 5) Appendix A, core plate hold-down bolt analysis to the BFN units, based on the configuration and the geometry of the BFN core plate hold-down bolts and the reactor environment (temperature and neutron fluence) assumed in the report.

In its response, by letter dated May 31, 2005, the applicant stated that the BFN core plate corresponds to that in BWRVIP-25, Figure 2-4, and that BFN was specifically considered in the original BWRVIP-25 evaluation, incorporating typical values of temperature and fluence. An analysis was initially performed for a 40-year plant life, and subsequently for a 60-year plant life, as discussed in BWRVIP-25, Appendix B, paragraph B.4, which addressed license renewal. This initial BWRVIP-25 based analysis assumed 20 percent hold-down bolt preload relaxation over a 60-year plant life.

To address EPU conditions in conjunction with license renewal, the applicant stated that a plant-specific calculation was performed for the BFN units. This calculation was based on the BFN fluence calculation which was performed considering EPU operating power and time conditions. The applicant stated that the applicable maximum bolt fluence was determined to be 5×10^{19} n/cm^2 (E > 1MeV) at the end of the 60-year plant life. The resulting hold-down bolt load relaxation was determined to be 15 percent, based on General Electric Nuclear Energy (GENE) design documents.

The staff reviewed this response and concluded that additional information was needed to complete its evaluation. The additional information was requested in the follow-up to RAI 4.7.7-1 which is discussed later.

In RAI 4.7.7-2, dated March 3, 2005, the staff requested that the applicant:

(a) Identify the temperature of the bolts during the normal operation and the projected bolt neutron fluence at the end of the period of extended operation.

(b) Explain how it was determined that the effects of temperature and neutron fluence result in a 20 percent loss of preload.

(c) Provide a detailed description of the methodology and data used at BFN to perform the analysis as described in (b), and include the basis for the relaxation curves.

In its response to RAI 4.7.7-2, dated May 31, 2005, the applicant responded as follows:

(a) The normal operating temperature for the core plate bolts is 550°F. For the BFN units, the projected fluence was determined to be 5 x 10^{19} n/cm^2 (E > 1MeV) for a 60-year lifetime, (assuming a 90 percent capacity factor) for the bolt at the peak radial location. The arrangement of the bolts around the periphery of the core plates assures that many of the bolts experience a significantly lower lifetime fluence.

(b) The plant-specific evaluation used GENE proprietary relaxation curves from a GENE material design document for irradiated stainless steel properties at 550°F, that was developed in the1970s time frame. The document was based on a combination of GENE internal reports and industry data to evaluate bolt stress relaxation.

(c) The BFN calculation was performed based on the BFN-specific core plate geometry, fluence and temperature. The BFN fluence conditions and the expected bolt stress relaxation made use of either GENE methods or GENE design documents. In support of the relaxation value used in the calculations, the applicant provided relaxation vs. fluence data from BWRVIP-99, "Crack Growth Rates in Irradiated Stainless Steels In BWR Internal Components." (Reference 6). This data was developed for type 316 stainless steel material, based on data found in the literature. The applicant justified the application to type 304 stainless steel material on the basis that the two commercial material alloys have the same single-phase austenitic microstructure and crystal structure, with no precipitates present in either alloy, and the mechanical properties are essentially identical at 550°F.

The staff reviewed the information in this response and concluded that additional information was needed to complete its evaluation. The additional information was requested in RAI 4.7.7-3 through 4.7.7-7 by letter dated June 22, 2005.

In RAI 4.7.7-3, dated June 22, 2005, the staff requested that the applicant provide the data that GENE used to develop the stress relaxation curves and explain how this data was utilized to establish the curves.

In its response, by letter dated June 29, 2005, the applicant presented a mean design curve developed by GENE using stress relaxation values of irradiated stainless steel materials. The data was obtained from measurements made on springs and bent-beam specimens.

The staff's review of the applicant's response to RAI-4.7.7-3 is included in the staff's review of RAI 4.7.7-4.

In RAI 4.7.7-4, dated June 22, 3005, the staff stated that the applicant referenced BWRVIP-99 report, Figure 7-13, which shows data and modeling projections for stress relaxation versus fluence values measured in displacements per atom (dpa) for 20 percent cold-worked type 316 stainless steel material. The staff requested that the applicant provide an explanation justifying the applicability of the Type 316 stainless steel data to the Type 304 stainless steel core plate hold-down bolts at the BFN units.

In its response, by letter dated June 29, 2005, the applicant stated that the stress relaxation property of irradiated stainless steel materials does not vary with change in chemical composition. To support this claim, the applicant provided Halden (in-situ tests in the Halden reactor) data which show that there is very small variation in stress relaxation values between Type 304, 316, and 348 stainless steel specimens. The stress relaxation data were obtained from specimens that were exposed to 4.4 to 6 x 10^{20} n/cm^2 (E > 1MeV) in 288 °C water. These neutron fluence values are nearly 10 times higher than that of BFN core plate hold down bolts; therefore, stress relaxation values for the BFN bolts will be less than the values that are presented in the data. The applicant compared the Halden data with GENE data and concluded that for a given neutron fluence value the corresponding stress relaxation value that is obtained from the GENE data is more conservative than that from the Halden data.

The staff reviewed the applicant's responses to RAIs 4.7.7-3 and 4.7.7-4 and concluded that supporting data to the applicant's claim that the variation in chemical composition of stainless steel materials has very little effect on the stress relaxation of the irradiated stainless steel materials. Therefore, the staff concluded that the stress relaxation curves for the irradiated Type 316 stainless steel material can be applicable to irradiated Type 304 stainless steel materials. The staff reviewed the data in the applicant's response dated June 29, 2005, and found that for a given neutron fluence value the corresponding stress relaxation value obtained from GENE data is conservative and is acceptable.

In RAI 4.7.7-5, dated June 22, 2005, the staff requested that the applicant provide the dpa values for Type 304 core plate hold-down bolts that correspond to end-of-life fluence (54 EFPY) using appropriate model for the BFN units.

The staff’s review of the applicant’s response to RAI 4.7.7-5 is included in the staff’s review of the follow-up to RAI 4.7.7-1.

In RAI 4.7.7-6, dated June 22, 2005, the staff requested that the applicant provide justification for the application of relaxation curves obtained based on data from torsion tests to axial relaxation in bolts.

In its response, by letter dated June 29, 2005, the applicant stated that the GENE stress relaxation data is obtained from test samples that include springs that represent torsional loading, and bent-beam specimens that represent tension loading. The applicant presented stress relaxation data that represented tension loading and another set representing shear loading, and they both exhibit similar behavior as GENE stress relaxation curve, but at a lower value. The data also indicated that the stress relaxation curve was not affected by the specimen or type of loading. Therefore, the applicant concluded that the stress relaxation values that are presented are applicable for torsional and axial loadings.

The staff reviewed the applicant's response and concluded that the stress relaxation curves and the applicant's presented data on the stress relaxation values are applicable for torsional and axial loadings.

In RAI 4.7.7-7, dated June 22, 2005, the staff requested that the applicant provide the calculations referenced in Appendix B of BWRVIP-25 so that it can evaluate the stress relaxation of the core plate hold-down bolts for the end-of-license fluence (54 EFPY) for the BFN units.

In its response to RAIs 4.7.7-5 and 4.7.7-7, dated June 29, 2005, the applicant provided a proprietary response in reply to the staff RAIs (ADAMS Accession No: ML052150189). In the response the applicant stated that a plant-specific calculation was performed for the BFN units using a neutron fluence value of 5×10^{19} n/cm^2 (E > 1MeV) which is equivalent to 0.07 displacement damage (measured as dpa) at the peak fluence location. The dpa value is calculated based on the calculated fast fluence and an effective dpa cross section (E > 1 MeV) of approximately 1380 barns for steel. The GENE stress relaxation value for this neutron fluence and dpa values is 15 percent, which is a conservative value, falls within the bounding value of 20 percent that was specified in the BWRVIP-25 report. The staff's review of the applicant's response to RAI-4.7.7-5 is included in the staff's review of the follow-up to RAI 4.7.7-1.

The staff reviewed the information in the responses to RAI 4.7.7-3 through 4.7.7-7, and concluded that additional information was needed to complete its evaluation. The additional information was requested in follow-up to RAI 4.7.7-1 and 4.7.7-2 by letter dated August 2, 2005.

In the follow-up to RAI 4.7.7-1, dated August 2, 2005, the staff indicated that in the data provided by TVA in its submittal dated June 29, 2005, the applicant compared the stress relaxation for the BFN core plate hold-down bolts to the stress relaxation data derived from springs and stainless steel bent beam specimens. The staff requested that the applicant provide information regarding the values of neutron flux and temperature at which the bent beam and spring test specimens were exposed, and compare them to the neutron flux and temperature values of the BFN core plate hold-down bolts. If these neutron flux and temperature values are different from those for the spring and bent beam specimens, the staff requested that the applicant evaluate the impact of these differences on the predicted stress relaxation values of the BFN core plate hold-down bolts.

In its response to the follow-up to RAI 4.7.7-1, dated September 6, 2005, the applicant addressed the effects of temperature and neutron flux on the stress relaxation values at which the irradiation tests were conducted. In its response, the applicant stated that given the large range of higher flux for which the properties are the same, the impact of the lower flux to which the bolts are exposed is viewed to be negligible. In support, the applicant stated that the temperature and fluxes associated with the design basis data are appropriate for use in predicting stress relaxation in the BFN core plate bolts. The test data was all generated at temperatures from 530°F to 600°F and, therefore, is fully representative of BWR operating conditions. The nuclear spectrum is also similar to that for the core plate bolt region. While the test data was generated at higher fluxes than present in the core plate region, the applicability of the data for use in the core plate bolt assessment is supported by mechanistic understanding as well as component test results.

Since the temperatures at which the majority of the irradiation tests were conducted represent the temperatures of the core plate hold-down bolts at the BFN units, the applicant claimed that the stress relaxation data that was provided by GENE would be representative of the BFN core plate hold-down bolts. The applicant further reiterated that the tests conducted at a neutron flux value higher than that of the core plate hold down bolts can be applicable for evaluating the stress relaxation data for the BFN's core plate hold-down bolts.

The staff reviewed the applicant's responses to the aforementioned RAI and determined that the applicant's justification for using the GENE methodology in the applicant's response in developing the stress relaxation curves is acceptable for the following reasons. GENE developed the stress relaxation curve for irradiated austenitic stainless steel materials at temperatures equivalent to the BWR normal operating temperatures and at a neutron fluence value equivalent to 54 EFPY for the BFN units. The stress relaxation data demonstrates that the impact of test temperature and neutron flux values for the test samples are not significant. The stress relaxation curve indicates that the relaxation value for the neutron fluence equivalent to 54 EFPY at the BFN units is 15 percent. The staff concluded that the stress relaxation value of 15 percent is a conservative value and falls within the bounding value of 20 percent that was provided in the generic analysis of the staff-approved BWRVIP-25 report.

In the follow-up to RAI 4.7.7-2, dated August 2, 2005, the staff requested that the applicant show that, under design basis accident condition loading stated in Scenario 3 of BWRVIP-25, Appendix A, the axial and bending stresses for the mean and highest loaded hold-down bolts will not exceed the ASME Section III allowable stresses for P_m (primary membrane) and $P_m + P_b$ (primary membrane plus bending) as a result of a 20 percent reduction in the specified bolt pre-load. The staff also requested that the applicant state clearly the assumptions on which the analysis was based.

In its response to the follow-up RAI 4.7.7-2, dated September 6, 2005, the applicant indicated that the BFN current licensing basis states that: "Two considerations important to the core support evaluation are sliding of the core support and buckling of the supporting beams. Evaluations have determined that the core support will not slide under postulated accident conditions with preload on the hold-down bolts. Additional resistance to sliding is provided by aligning pins which further stabilize the core support." The applicant also provided a (proprietary) stress calculation of the hold-down bolts which demonstrated that the axial and bending stresses met the stress criteria in BWRVIP-25, Appendix A.

The staff reviewed the applicant's response and identified the following concerns:

- The analysis does not correspond to the plant-specific core plate/hold-down bolt analysis recommended in Appendix A of BWRVIP-25. The applicant's analysis assumes that the core plate is rigid. The recommended approach is based on an elastic finite element analysis of the core plate/hold-down bolts.
- The applicant selected friction due to hold-down bolt preload as the means to prevent sliding of the core plate under horizontal loading. BWRVIP-25 recommends the

installation of wedges to prevent sliding; it does not recommend high preload to induce sufficient friction to prevent sliding. No basis for this choice was provided.

- The analysis is based on stipulated high preload (including 20 percent relaxation) of the hold-down bolts and a high static coefficient of friction to prevent sliding of the core plate under accident basis horizontal loading. No basis was provided for this high static coefficient of friction. Based on a comparison with values found in the literature, the coefficient of friction used in the analysis is similar to that stipulated as friction between dry metal surfaces. This value is not considered applicable to friction between the core plate and its shroud support, which are immersed in a BWR hot water environment. The staff believes that the static coefficient of friction in this environment is considerably lower, similar to that for friction between lubricated metal surfaces.

- As a result of the assumed rigidity of the core plate and high coefficient of static friction, and leading to the prevention of sliding under horizontal loading, the only stress state in the hold-down bolts is axial, caused by the bolt pre-load and vertical loading on the core plate. The core plate/hold-down bolt analysis in BWRVIP-25, Appendix A is based on relatively low bolt pre-load and no friction. As a result, the core plate is restrained from sliding by the hold-down bolts only, which induces bending stresses in the bolts. A low coefficient of friction may show that core plate sliding under the horizontal loading may not be prevented, thus inducing bending stresses in the hold-down bolts, in addition to the axial stresses.

- BWRVIP-25 indicates that "of special interest is the amount of bending induced in the bolts when the core plate bows upward, or when load from the beams is no longer transferred to the rim." This effect cannot be determined from the applicant's analysis if the core plate is assumed rigid.

- The stipulated hold-down bolt preload in the applicant's analysis is considerably larger that the preload in the analysis in BWRVIP-25, Appendix A. The effect of this preload on the structural integrity of the core plate was not evaluated.

- The finite element analysis of the core plate/hold-down bolts in Appendix A shows that the axial and transverse bolt loads vary around the circumference of the core plate. The axial loads in the highest loaded bolts are about twice the mean of the axial bolt loads. The applicant's analysis, based on a rigid plate analysis, shows that all bolts are uniformly loaded in tension and does not reflect the true distribution of the bolt loads.

- BWRVIP-25 specifies the design basis accident loads that should be considered in a plant-specific analysis. It is not clear that all applicable loads were considered in the applicant's analysis.

Based on these concerns, the staff concluded that the applicant did not provide reasonable assurance that the axial and bending stresses in the hold-down bolts will meet the ASME Section III primary stress limits as stated in BWRVIP-25, Appendix A, under the BFN plant-specific design basis accident loading and with 20 percent relaxation of hold-down bolt preload. This was, therefore, identified by the staff as Open Item 4.7.7.

Follow-up teleconferences with the applicant were held on October 14 and 18, 2005, to address the resolution of Open Item 4.7.7. This open item was included as one of four open items in an interim evaluation by the Advisory Committee on Reactor Safeguards of BFN's license renewal application and in the NRC's draft Safety Evaluation Report. By letter dated October 31, 2005, the staff provided the applicant a summary and discussion of the teleconferences, in which the staff position on this open item was summarized. The letter summarized the staff's concerns, as follows:

The applicant did not use the staff-approved analysis that was used in BWRVIP-25 report for the BFN units. The methodology used in the BWRVIP-25 report is more conservative. For BFN units, the applicant used a less conservative methodology, such as using a high static coefficient of friction value to ensure prevention of sliding of the core plate which eliminated the bending stresses in the core plate hold-down bolts. The staff determined that the static coefficient of friction used by the applicant is not supported by the available information provided in the literature.

The staff also questioned whether the applicant had considered using wedges to prevent core plate sliding, and if the wedges are installed, the aging management of core plate hold-down bolts will not be considered a TLAA item. The applicant stated that this option was evaluated but it is costly to install wedges in each unit. This option was, therefore, withdrawn.

The staff identified and summarized the following concerns:

(1) The analysis is significantly different from the structural analysis in BWRVIP-25, and is not based on a finite element model of the core plate.

(2) It is not clear that all loads listed in BWRVIP-25, such as fuel lift load, were included in the analysis.

(3) The applicant selected friction due to high bolt preload (significantly larger than that specified in BWRVIP-25) as the means to prevent side motion of the core plate. BWRVIP-25 recommends the use of wedges to prevent side motion; it does not recommend high bolt preload and friction.

(4) The applicant analysis assumes a high static coefficient of dry friction as the mechanism to prevent side motion of the core plate. The staff questions the basis for this assumption for a core plate that is in a BWR water environment.

(5) BWRVIP-25, Appendix A, page 4-6 states that "of special interest is the amount of bending induced in the bolts when the core plate bows upward, or when load from the beams is no longer transferred to the rim." No such bending was evaluated in the applicant's analysis.

(6) The BWRVIP-25 structural analysis shows a variation of the axial forces in the hold-down bolts with location around the plate circumference, and that the axial force in the highest-loaded bolt is about twice the mean axial bolt load. The applicant analysis shows that all bolts are uniformly loaded in tension. This indicates that the highest stresses in the hold-down bolts have not been determined.

(7) The effect of the large bolt preloads on the structural integrity of the core plate was not evaluated.

The staff stated its position that, for the BFN units, the applicant should apply the staff-approved methodology that was used in the BWRVIP-25 report.

By letter dated November 16, 2005, the applicant stated in Enclosures 3 and 9 the following commitment for BFN for the core plate hold-down bolts:

The applicant will perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand normal, upset, emergency, and faulted loads, as applicable, considering the effects of stress relaxation until the end of the period of extended operation. The installed core plate configuration and bolt preload will be used for the plant-specific analysis. The analysis will use the plant-specific design basis loads and load combinations. The analysis will incorporate detailed flux/fluence analyses and improved stress relaxation correlations.

In accordance with BFN's CLB, the ASME Boiler and Pressure Code, Section III will be used as a guide in determining limiting stress intensities for reactor vessel internals. For those components for which stresses exceed the ASME Code allowables, either the elastic stability of the structure or the resulting deformation or displacement will be examined to determine if the safety design basis is satisfied. Appropriate corrective action will be taken if the plant-specific analysis does not satisfy the above criteria. The installation of core plate wedges to eliminate the need for the enhanced inspections of the core plate hold-down bolts as recommended by BWRVIP-25 is considered an acceptable corrective action.

The analysis or the corrective action taken to resolve this issue will be submitted to the staff for review two years prior to the period of extended operation.

The staff reviewed the applicant's commitment and concluded that it provides adequate assurance that the 60-year stress relaxation of the core plate hold-down bolts due to neutron exposure will not compromise the structural integrity and operability of the core plate to the end of the period of extended operation. Open Item 4.7.7 is, therefore, closed.

4.7.7.3 UFSAR Supplement

In a letter dated November 16, 2005, the applicant revised LRA Section A.3.5.6 to include the UFSAR supplement summary description for the TLAA on stress relaxation of the core plate hold-down bolts. On the basis of its review of the UFSAR supplement, the staff concluded that the summary description of the applicant's actions to address stress relaxation of the core plate hold-down bolts is adequate.

4.7.7.4 Conclusion

The staff concluded that the applicant's commitment to provide a revised analysis, two years prior to the start of the period of extended operation, regarding the stress relaxation TLAA of the core plate hold-down bolts, and that the analysis will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii), is acceptable. The staff also concluded that the UFSAR supplement contains an appropriate summary description of this TLAA evaluation, sufficient to satisfy the requirements of 10 CFR 54.21(d).

4.7.8 Emergency Equipment Cooling Water Weld Flaw Evaluation

4.7.8.1 Summary of Technical Information in the Application

The TLAA of the EECW weld flaw evaluation is discussed in LRA Section 4.7.8. The applicant performed an analysis on 17 selected EECW system piping welds that have flaws. The original analysis included a stress evaluation of the flawed welds and fatigue crack growth calculations. The fatigue crack growth calculations were based on a conservative projection of 125 cycles for the remaining 25 years of the 40-year plant operating life based on five cycles per year. A cycle occurs when piping, including a subject weld, is removed from service then returned to service. This projection was derived from a very conservative estimate that each weld could experience up to five cycles per year. Review of the system function indicated that continuous operation is intended; however, some interruptions have been required for maintenance and other considerations. The applicant considers the fatigue crack growth portion of this analysis to be a TLAA.

As part of the LRA, the applicant found, based on current and recent plant operating experience, that it is unusual for any of these weld locations to experience more than one cycle in any given year. For the TLAA, the applicant assumed two cycles per year for the past and the foreseeable future. The cycle count of two cycles per year was applied to the 25 remaining operating years (projected when the calculations were performed), plus the 20 years of extended operation, resulting in a total cycle count of 90. This is less than the estimated cycle count used for qualification in the original calculation. Therefore, the applicant's position is that in accordance with 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation.

4.7.8.2 Staff Evaluation

As required by 10 CFR 54.21, applicants for license renewal must manage time-dependent aging effects by one of three acceptable methods:

1. Demonstrate that the TLAA on the aging effect for the current operation term remains valid for the period of extended operation.
2. Demonstrate that the TLAA on the aging effect for the current operation term and has been projected to the end of the period of extended operation.
3. Demonstrate that the effect of aging on the intended functions will be adequately managed for the period of extended operation.

In RAI 4.7.8-1, dated November 4, 2004, the staff requested that the applicant provide background information, including the code class, flaw inspection history, flaw sizes, and a description of any analysis including the method that was used to determine the flaw evaluation. In its response, by letter dated December 9, 2004, the applicant stated, in part:

> The flawed EECW welds are on BFN Seismic Class I piping that was designed to the B31.1-1967 Power Piping Code. For the BFN ASME Section XI program the welds are classified as ASME Class 3. Design conditions for the EECW system are 200 psig and 200 °F. All of the related piping is qualified by analysis. This analysis satisfies BFN

Design Criteria No. BFN -50-C-7103 which supplements B31.1 analysis requirements by invoking plant condition dependent stress equations from ASME Section III, 1971 Edition, Summer 1973 Addenda. The stress analyses of the piping systems are also considered a Time Limited Aging Analysis (TLAA) which is addressed in the Application TLAA Section 4.3.3.

History of Discovery – A weld inspection program was initiated at BFN to determine the effects of MIC on the stainless steel piping girth butt welds in the EECW system, as a result of MIC discoveries at other plants. The inspection program was implemented by performing radiography on a sample of EECW piping welds. Radiography had not been performed on these welds during installation, as it was not required by the applicable code and specifications. The inspection identified defects in 33 welds. The 33 welds which had identified defects were reviewed by the ISI Level III interpreter and 27 of the welds were rejected because they did not meet ISI flaw acceptance standards. The ISI Level III interpreter determined that the other welds did meet flaw acceptance standards.

Analysis Performed – Two analyses were performed in association with the qualification of the remaining 27 EECW welds with welding defects.

The applicant performed a bounding fracture mechanics analysis for the scope of stainless steel EECW pipe sizes encompassing the 27 welds that had been rejected based on ASME Section XI acceptance standards. Of the 27 welds, 10 were found to be acceptable using the bounding fracture mechanics analysis. The remaining 17 welds are the subject of the TLAA.

For the 17 welds identified in LRA Section 4.7.8, the applicant indicated that a location-specific fracture mechanics analysis was performed. The weld-specific analysis applied essentially the same approach and considerations as the bounding analysis except that location-specific stresses determined for ASME Code Section III, Subsection NC-3652, Equations 9 and 10 in the piping analyses of record were used to calculate both the ASME Code Section XI allowable flaw size and the fatigue crack growth due to cyclic load for the 25 years remaining in the plant life. The applicant found that for the controlling location (i.e., maximum thermal stress) in each pipe size applicable to the 17 welds, fatigue crack growth for the 25-year period was insignificant. Although the staff did not perform a detailed review of the applicant's analysis, the staff found the applicant's approach acceptable. The remaining issue is whether the applicant's demonstration that the TLAA on the aging effect for the current operation term remains valid for the period of extended operation.

The applicant stated in its LRA that, based on current and recent plant experience, it is unusual for any of these weld locations to experience more that one cycle in any given year.

The applicant stated that review of the EECW system indicates that continuous operation is intended; however, some interruptions have been required for maintenance and other considerations. Through an informal request on January 31, 2005, the staff requested the applicant to provide the following information as a follow-up to RAI 4.7.8: (a) Based on the design function of the EECW system, discuss when and at what frequency would the system be shut down; (b) Based on the design function and the total past history, discuss whether the number of cycles in the fatigue evaluation bound the number of cycles projected for the period of extended operation; (c) Describe events, and the frequency that they have occurred, that resulted in system operational interruptions; and (d) Should the EECW system experience more cycles than is bounded by the applicant's analysis, discuss any plant procedures in place to identify this condition.

The applicant responded by letter on March 2, 2005, and provided the following as a follow up to RAI 4.7.8:

> The EECW system is intended to be in a continuous standby condition (i.e. under pressure-minimum flow) in both shutdown and operating plant modes. As currently designed, sections of this system may be isolated and depressurized for routine maintenance or repair. Based on operating history and future (anticipated operations) a total of 125 full pressure cycles (0 psig to design operating pressure) was selected as a conservative measure to ensure the number of fatigue cycles would not be exceeded. The preventative maintenance work orders scheduled on this system are of a periodicity of no less than 96 weeks (almost 2 years) and unless unexpected repairs are required, the system would not need to be depressurized. Using a conservatism of a little over 2 times in a year makes sense for it would be very unlikely for the same Section of the EECW system to be shutdown [sic] > 2 times in a year. Please review preventative maintenance scheduled items on [the] following page [Not included in this evaluation. See March 2, 2005 letter]. An administrative tracking system will be developed and used to ensure that the 125 fatigue cycles will not be exceeded.

Based on operating history and anticipated future operations coupled with the applicant's commitment to develop an administrative tracking system to ensure that the EECW system does not exceed the applicant's 125 full pressure cycles, the staff concluded that the EECW weld flaw evaluation is valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) and is, therefore, acceptable.

4.7.8.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of EECW weld flaw evaluation in LRA Section A.3.5.7. On the basis of its review, and the responses to the staff's RAIs, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on EECW weld flaw evaluation and is, therefore, acceptable.

4.7.8.4 Conclusion

The staff reviewed the applicant's TLAA on EECW weld flaw evaluation, as summarized in LRA Section 4.7.8, including information submitted in response to the staff's RAIs, and determined that the effects of EECW weld flaw evaluation will be adequately managed. Therefore, the staff concluded that the applicant has demonstrated that the effects of EECW weld flaw evaluation 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(c)(1)(iii).

4.8 Conclusion for Time-Limited Aging Analyses

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concluded that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concluded that the applicant demonstrated that (1) the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i); (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii); or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and found that the UFSAR supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concluded that no plant-specific exemptions are in effect that are based on TLAAs, pursuant to 10 CFR 54.21(c)(2).

With regard to these matters, the staff concluded that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB, and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and the NRC's regulations.

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SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS[1]

In accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for the Browns Ferry Nuclear (BFN) Units 1, 2, and 3. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. The applicant and staff from the U.S. Nuclear Regulatory Commission (the staff) will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRAs.

After the ACRS completes its review of the LRAs and the SER, the full committee will issue a report discussing the results of its review. An update to this SER will include the ACRS report. This update will also include the staff's response to any issues and concerns identified in the ACRS report.

[1] This section is revised. See BFN LRA SER Supplement 1.

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SECTION 6

CONCLUSIONS[1]

The staff of the U.S. Nuclear Regulatory Commission (NRC or the Commission) reviewed the license renewal applications for the Browns Ferry Nuclear, Units 1, 2, and 3, in accordance with Commission regulations and NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated July 2001. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its evaluation of the license renewal applications, the NRC staff concluded that the requirements of 10 CFR 54.29(a) have been met and that all open items and confirmatory items have been resolved.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in Supplement 21 to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Browns Ferry Nuclear, Units 1, 2, and 3, Final Report,” dated June 23, 2005.

[1] This section is revised. See BFN LRA SER Supplement 1.

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APPENDIX A
COMMITMENTS FOR LICENSE RENEWALS OF BFN UNITS 1, 2, AND 3[1]

During the review of the Browns Ferry Nuclear Plant (BFN) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff, the applicant made commitments related to aging management programs (AMPs) to manage aging effects of structures and components (SCs) before the period of extended operation. The following tables list these commitments, along with the implementation schedules and the sources of the commitments.

- Table 1 lists those commitments that are not for a specific unit.
- Table 2 lists commitments that are specific to Unit 1.

Note that these tables also contain non-AMP commitments.

[1] This commitment table is revised. See BFN LRA SER Supplement 1

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TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
1. Accessible Non-Environmental Qualification Cables and Connections Inspection Program	Develop and implement new program.	A.1.1	Prior to the period of extended operation	• LRA Section B.2.1.1
2. Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program	Revise implementing documents for LPRM cable system aging to reference existing Technical Specification requirements and license renewal reference(s).	A.1.2	Prior to the period of extended operation	• LRA Section B.2.1.2 • Response to follow-up to RAI 2.5-2 dated March 2, 2005
	Develop and implement new program to manage IRM cable system aging.		Prior to the period of extended operation	• LRA Section B.2.1.2 • Response to follow-up to RAI 2.5-2 dated March 2, 2005
3. Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program	Develop and implement new program to manage the medium-voltage cables to the Residual Heat Removal Service Water pumps.	A.1.3	Prior to the period of extended operation	• LRA Section B.2.1.3 • Response to RAI 3.6-3(a) dated December 9, 2004 • Response to follow-up RAI 3.6-3 dated January 18, 2005
4. ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program	Revise implementing documents to include license renewal reference(s).	A.1.4	Prior to the period of extended operation	• LRA Section B.2.1.4

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
5. Chemistry Control Program	Revise implementing documents to include license renewal reference(s).	A.1.5	Prior to the period of extended operation	• LRA Section B.2.1.5
6. Reactor Head Closure Studs Program	Revise implementing documents to include license renewal reference(s).	A.1.6	Prior to the period of extended operation	• LRA Section B.2.1.6
7. Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program	Revise implementing documents to include license renewal reference(s).	A.1.7	Prior to the period of extended operation	• LRA Section B.2.1.7
8. Boiling Water Reactor Feedwater Nozzle Program	Revise implementing documents to include license renewal reference(s).	A.1.8	Prior to the period of extended operation	• LRA Section B.2.1.8
9. Boiling Water Reactor Control Rod Drive Return Line Nozzle Program	Revise implementing documents to include license renewal reference(s).	A.1.9	Prior to the period of extended operation	• LRA Section B.2.1.9
10 Boiling Water Reactor Stress Corrosion Cracking Program	Revise implementing documents to include license renewal reference(s).	A.1.10	Prior to the period of extended operation	• LRA Section B.2.1.10
11. Boiling Water Reactor Penetrations Program	Revise implementing documents to include license renewal reference(s).	A.1.11	Prior to the period of extended operation	• LRA Section B.2.1.11 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
12. Boiling Water Reactor Vessel Internals Program	Revise implementing documents to include license renewal reference(s).	A.1.12	Prior to the period of extended operation	• LRA Section B.2.1.12
	Inspect the top guide beams		Prior to the period of extended operation	• Response to NRC Question (3) dated May 25, 2005
	Establish an aging management program for the steam dryers.		Two years before the first BFN unit enters the period of extended operation	• Response to RAI 3.1-1 dated January 31, 2005
	Enhance the Reactor Pressure Vessel Internals Inspection (RPVII) Units 1, 2, and 3 procedure to require visual inspection of the Access Hole Covers (AHCs) and inspection of the AHC welds.		Two years before the first BFN unit enters the period of extended operation	• Response to RAI B.2.1.12-1(C) dated January 31, 2005 • Response to NRC Question (7) dated May 25, 2005
	Implement the inspection of weld TS-2 (BWRVIP-41).		When inspection technique for weld TS-2 being developed by the BWRVIP Inspection Committee is available.	• Response to Question (12) dated May 25, 2005
13. Flow-Accelerated Corrosion Program	Revise implementing documents to include license renewal reference(s).	A.1.14	Prior to the period of extended operation	• LRA Section B.2.1.15
14. Bolting Integrity Program	Revise implementing documents to include license renewal reference(s).	A.1.15	Prior to the period of extended operation	• LRA Section B.2.1.16

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
15. Open-Cycle Cooling Water System Program	Revise implementing documents to include license renewal reference(s).	A.1.16	Prior to the period of extended operation	• LRA Section B.2.1.17
16. Closed-Cycle Cooling Water System Program	Revise implementing documents to include license renewal reference(s).	A.1.17	Prior to the period of extended operation	• LRA Section B.2.1.18
17. Inspection of Overhead Heavy Load and Light Load Handling Systems Program	Revise implementing documents to include license renewal reference(s).	A.1.18	Prior to the period of extended operation	• LRA Section B.2.1.20
18. Compressed Air Monitoring Program	Revise implementing documents to: • Include license renewal reference(s). • Incorporate guidelines in ASME OM-S/G-2000, Part 17; ANSI/ISA-S7.0.01-1996; and EPRI TR 108147	A.1.19	Prior to the period of extended operation	• LRA Section B.2.1.21
19. BWR Reactor Water Cleanup System Program	Revise implementing documents to include license renewal reference(s).	A.1.20	Prior to the period of extended operation	• LRA Section B.2.1.22
20. Fire Protection Program	Revise implementing documents to include license renewal reference(s).	A.1.21	Prior to the period of extended operation	• LRA Section B.2.1.23

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
21. Fire Water System Program	Revise implementing documents to: • Include license renewal reference(s). • Perform flow tests or non-intrusive examinations to identify evidence of loss of material due to corrosion.	A.1.22	Prior to the period of extended operation	• LRA Section B.2.1.24
	Perform sprinkler head inspections to ensure signs of degradation, such as corrosion, are detected in a timely manner.		Prior to exceeding the 50-year service life for any sprinkler	• LRA Section B.2.1.24
22. Aboveground Carbon Steel Tanks Program	Revise implementing documents to include license renewal reference(s).	A.1.23	Prior to the period of extended operation	• LRA Section B.2.1.26
23. Fuel Oil Chemistry Program	Revise implementing documents to include license renewal reference(s).	A.1.24	Prior to the period of extended operation	• LRA Section B.2.1.27 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
24. Reactor Vessel Surveillance Program	Revise implementing documents to include license renewal reference(s).	A.1.25	Prior to the period of extended operation	• LRA Section B.2.1.28
	Enhance the Integrated Surveillance Program (ISP) per proposed BWRVIP-116.		Prior to the period of extended operation	• LRA Section B.2.1.28
	If the ISP is not approved two years prior to the commencement of the license renewal period, a plant-specific surveillance program for each BFN unit will be submitted to the NRC.		Two years prior to the commencement of the license renewal period	• Response to RAI B.2.1.28-1(A) dated January 31, 2005 • Response to Question (9) dated May 25, 2005
	Maintain Unit 1 and Unit 3 surveillance capsules (standby capsules) available to the ISP.		Unit 3 is ongoing Unit 1 will commence at restart	• Response to Question (10) dated May 25, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
25. One-Time Inspection Program	Develop and implement new program.	A.1.26	Prior to the period of extended operation	• LRA Section B.2.1.29
	Develop and submit procedure for NRC review.		At least two years prior to the expiration of the current operating license	• Response to Proposed Unresolved Item 3.0-4 LP dated May 27, 2005
	Perform a one-time inspection of the ASME equivalent Class MC supports in a submerged environment of the Units 2 and 3 Torus.		Prior to the period of extended operation	• Response to RAI B.2.1.33-2 dated January 18, 2005
	Perform a one-time inspection of the in-scope submerged concrete in one individual CCW pump bay of the Intake Pumping Station.		Prior to the period of extended operation	• Response to Question 359 dated October 8, 2004 • Response to RAI 3.5-16 dated April 5, 2005
	Perform ultrasonic thickness measurements of tank bottoms for those tanks specified in the Fuel Oil Chemistry Program (B.2.1.27) and the Aboveground Carbon Steel Tanks Program (B.2.1.26).		Prior to the period of extended operation	• Response to RAI 7.1.19-1 dated May 25, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
26. Selective Leaching of Materials Program	Develop and implement program.	A.1.27	Prior to the period of extended operation	• LRA Section B.2.1.30
27. Buried Piping and Tanks Inspection Program	Revise implementing documents to include license renewal reference(s).	A.1.28	Prior to the period of extended operation	• LRA Section B.2.1.31
	Add a trigger to the excavation permit document to require notification of engineering to perform a piping inspection when piping is excavated.		Complete	• NRC Inspection Report dated January 27, 2005
	Determine (via engineering evaluation) if sufficient inspections have been performed to draw conclusion regarding ability of underground coating to protect piping. If required, conduct a focused inspection to draw conclusion concerning the coating.		Within ten years after entering the period of extended operation	• Response to RAI 7.1.22-1 dated May 25, 2005
	Revise implementing documents to inspect buried piping when it is excavated.		Complete	• Response to RAI 7.1.22-1 dated May 25, 2005
28. ASME Section XI Subsection IWE Program	Revise implementing documents to include license renewal reference(s).	A.1.29	Prior to the period of extended operation	• LRA Section B.2.1.32

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
29. ASME Section XI Subsection IWF Program	Revise implementing documents to include license renewal reference(s).	A.1.30	Prior to the period of extended operation	• LRA Section B.2.1.33
	Enhance program to manage the aging effects of ASME equivalent Class MC supports.		Prior to the period of extended operation	• Response to Follow-up RAI B.2.1.33-1 dated May 31, 2005
30. 10 CFR 50 Appendix J Program	Revise implementing documents to include license renewal reference(s).	A.1.31	Prior to the period of extended operation	• LRA Section B.2.1.34
31. Masonry Wall Program	Revise implementing documents to include license renewal reference(s).	A.1.32	Prior to the period of extended operation	• LRA Section B.2.1.35
	Revise implementing procedures to clearly identify structures with masonry walls within scope and to clarify qualification requirements for personnel who perform masonry wall walkdowns.		Prior to the period of extended operation	• LRA Section B.2.1.35

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
32. Structures Monitoring Program	Revise implementing documents to include license renewal reference(s).	A.1.33	Prior to the period of extended operation	• LRA Section B.2.1.36
	Enhance procedures implementing the10 CFR 50.65 Maintenance Rule Program to identify all structures and structural components within scope.		Prior to the period of extended operation	• LRA Section B.2.1.36 • Response to GALL audit Question 173 dated October 8, 2004 • Response to GALL audit Question 357 dated October 8, 2004
	Enhance procedures implementing the 10 CFR 50.65 Maintenance Rule program sampling approach to include examinations of below-grade concrete when excavated.		Prior to the period of extended operation	• LRA Section B.2.1.36 • Response to GALL audit Question 285 dated October 8, 2004
	Enhance procedures implementing the 10 CFR 50.65 Maintenance Rule program to include the guidance provided in ACI 349.3R-96 Chapter 7.		Prior to the period of extended operation	• LRA Section B.2.1.36
	Enhance LCEI-CI-C9, Attachment 1, “Buried Piping Inspection Checklist,” to include “Mechanical Penetration” as an inspection attribute.		Prior to entering the period of extended operation	• Response to GALL audit Question 285 dated October 8, 2004

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
33. Inspection of Water-Control Structures Program	Revise implementing documents to include license renewal reference(s).	A.1.34	Prior to the period of extended operation	• LRA Section B.2.1.37
	Revise implementing documents to identify required structures and structural components within the scope of license renewal.		Prior to the period of extended operation	• LRA Section B.2.1.37
	Revise implementing documents to include special inspections following the occurrence of large floods, earthquakes, tornadoes, and intense rainfall.		Prior to the period of extended operation	• LRA Section B.2.1.37
	Implement periodic monitoring of the raw service water in close proximity to the Intake Pumping Station for the requirements of an aggressive environment.		Prior to the period of extended operation	• Response to RAI 3.5-16 dated April 5, 2005
34. Environmental Qualification Program	Revise implementing documents to include license renewal reference(s).	A.1.35	Prior to the period of extended operation	• LRA Section B.3.1
35. Fatigue Monitoring Program	Implement enhanced Fatigue Monitoring Program using the EPRI-licensed FatiguePro® cycle counting and fatigue usage tracking computer program.	A.1.36	Prior to the period of extended operation	• LRA Section B.3.2
36. Systems Monitoring Program	Revise implementing documents to include license renewal reference(s).	A.2.1	Prior to the period of extended operation	• LRA Section B.2.1.39 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
37. Bus Inspection Program	Develop and implement new program.	A.2.2	Prior to the period of extended operation	• LRA Section B.2.1.40 • Response to RAI 3.6-4 dated December 9, 2004
38. Diesel Starting Air Program	Revise implementing documents to include license renewal reference(s).	A.2.3	Prior to the period of extended operation	• LRA Section B.2.1.41
39. Time-Limited Aging Analysis: Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limits (P-T)	Develop and submit revised P-T limits to the NRC for approval.	A.3.1.5	Prior to the period of extended operation	• LRA Section A.3.1.5 • LRA Section 4.2.5
40. Time-Limited Aging Analysis: Environmental Qualification of Electrical Equipment	Revise existing EQ program to cover the extended period of operation.	A.3.3	Prior to the period of extended operation	• LRA Section A.3.3 • LRA Section 4.4
41. Time-Limited Aging Analysis: Other Plant Specific Time-Limited Aging Analysis: Emergency Equipment Cooling Water Weld Flaw Evaluation	Implement an administrative tracking system to ensure limiting number of fatigue cycles will not be exceeded at the select EECW locations.	A.3.5.7	Prior to the period of extended operation	• LRA Section A.3.5.7 • Response to RAI 4.7.8 dated March 2, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
42. RAI 2.1-2,A-3	Identify additional piping segments and supports/equivalent anchors to be placed in scope.	N/A	Complete	• Response to RAI 2.1-2,A-3 dated September 3, 2004 • TVA response dated February 28, 2005
43. RAI 2.1-2,B	Implement Unit 1, 2, and 3 DCNs to qualify twelve temperature switches in the Turbine Building.	N/A	Prior to the period of extended operation	• Response to RAI 2.1-2,B dated September 3, 2004
44. RAI 2.1-2,C RHRSW tunnel	Include 24-inch Raw Cooling Water discharge piping located in the RHRSW tunnel in scope of license renewal.	N/A	Complete	• Response to RAI 2.1-2,C RHRSW Tunnel dated September 3, 2004 • TVA response dated January 31, 2005
45. RAI 2.1-2,C Intake Pumping Station	Revise 10 CFR 54.4(a)(2) Scoping Methodology document to address components located in the lower compartments of the Intake Pumping Station.	N/A	Prior to next annual update	• Response to RAI 2.1-2,C Intake Pumping Station dated September 3, 2004
46. Open Item OI 2.4-3	Perform one time confirmatory ultrasonic thickness (UT) measurements on a portion of the cylindrical section of the drywell on Units 2 and 3.	N/A	Prior to the period of extended operation	• Enclosures 1 and 9 of TVA letter dated November 16, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
47. Open Item OI 4.7.7	Perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand required loads, considering the effects of stress relaxation until the end of the period of extended operation. Take appropriate corrective action if the analysis does not satisfy the specified criteria. Submit the analysis or the corrective action taken to resolve the core plate hold-down bolt issue to the NRC for review.	N/A	Two years prior to the period of extended operation	• Enclosures 3 and 9 of TVA letter dated November 16, 2005
48. Open Item from AMP Inspection on Inspection of RHRSW Piping	Perform a confirmatory inspection of the RHRSW pump pit supply piping. Include instructions in the CCW pump pit Preventive Maintenance Program to periodically inspect the sluice gate valves. Perform a confirmatory inspection of the seismic restraints in the RHRSW pump pit.	N/A	Prior to the period of extended operation	• Enclosures 4 and 9 of TVA letter dated November 16, 2005

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

NOTE: This Table does not contain all of the same Item Numbers as contained in Table 1. While there is a one-to-one correlation of items with the same number, the same Item Numbers are not in both tables as explained below:

- For Item Numbers 1. through 49., only those Item Numbers that have a Unit 1 specific commitment are included in this table.
- Item Number 63. applies only to Unit 1.

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
2. Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program	Include Unit 1 High-Range Radiation Monitoring cables in the Environmental Qualification (EQ) Program.	A.1.2	Prior to Unit 1 restart	• Response to GALL audit Question 169 dated October 8, 2004
5. Chemistry Control Program	Include Unit 1 in the program.	A.1.5	Prior to Unit 1 restart	• LRA Section B.2.1.5
7. Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program	Include Unit 1 in the program.	A.1.7	Prior to Unit 1 restart	• LRA Section B.2.1.7
8. Boiling Water Reactor Feedwater Nozzle Program	Upgrade Unit 1 operating procedures to decrease the magnitude and frequency of feedwater temperature fluctuations.	A.1.8	Prior to Unit 1 restart	• LRA Section B.2.1.8
10. Boiling Water Reactor Stress Corrosion Cracking Program	Include Unit 1 in the program.	A.1.10	Prior to Unit 1 restart	• LRA Section B.2.1.10 • Response to GALL audit Question 181 dated October 8, 2004

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
11. Boiling Water Reactor Penetrations Program	Include Unit 1 in the program.	A.1.11	Prior to Unit 1 restart	• LRA Section B.2.1.11 • Response to GALL audit Question 194 dated October 8, 2004
12. Boiling Water Reactor Vessel Internals Program	Include Unit 1 in the program.	A.1.12	Prior to Unit 1 restart	• LRA Section B.2.1.12 • Response to Question (4b) dated May 25, 2005
13. Flow-Accelerated Corrosion Program	Include Unit 1 in the program.	A.1.14	Prior to Unit 1 restart	• LRA Section B.2.1.15 • Response to GALL audit Question 144 dated October 8, 2004
15. Open-Cycle Cooling Water System Program	Include Unit 1 in the program.	A.1.16	Prior to Unit 1 restart	• LRA Section B.2.1.17 • Response to GALL audit Question 144 dated October 8, 2004
16. Closed-Cycle Cooling Water System Program	Include Unit 1 in the program.	A.1.17	Prior to Unit 1 restart	• LRA Section B.2.1.18 • Response to GALL audit Question 144 dated October 8, 2004
18. Compressed Air Monitoring Program	Include Unit 1 in the program.	A.1.19	Prior to Unit 1 restart	• LRA Section B.2.1.21

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

<table>
<tr><th>Item Number/Title</th><th>Commitment</th><th>LRA Appendix A (UFSAR)</th><th>Implementation Schedule</th><th>Source</th></tr>
<tr><td>19. BWR Reactor Water Cleanup System Program</td><td>Include Unit 1 in the program.</td><td>A.1.20</td><td>Prior to Unit 1 restart</td><td>• LRA Section B.2.1.22
• LRA Section F.13</td></tr>
<tr><td>20. Fire Protection Program</td><td>Update the Fire Protection Report and to incorporate Unit 1 as an operating unit. Fully implement the program on Unit 1.</td><td>A.1.21</td><td>Prior to Unit 1 restart</td><td>• LRA Section B.2.1.23</td></tr>
<tr><td>21. Fire Water System Program</td><td>Update the Fire Protection Report and procedures to incorporate Unit 1 as an operating unit. Fully implement the program on Unit 1.</td><td>A.1.22</td><td>Prior to Unit 1 restart</td><td>• LRA Section B.2.1.24</td></tr>
<tr><td rowspan="2">24. Reactor Vessel Surveillance Program</td><td>Either include Unit 1 within the BWRVIP ISP, or submit for NRC approval a plant specific surveillance program that meets the requirements of 10 CFR 50 Appendix H for the period of extended operation.</td><td rowspan="2">A.1.25</td><td>Prior to the period of extended operation</td><td>• LRA Section B.2.1.28</td></tr>
<tr><td>Ensure BWRVIP-86-A and BWRVIP-116 are revised to incorporate Unit 1, and submit to the NRC a license amendment request to implement the ISP for site-specific use for
Unit 1.</td><td>Prior to the period of extended operation</td><td>• Response to RAI B.2.1.28-1 dated January 31, 2005</td></tr>
<tr><td>25. One-Time Inspection Program</td><td>Perform a one-time inspection of the ASME equivalent Class MC supports in a submerged environment of the Unit 1 Torus.</td><td>A.1.26</td><td>Prior to Unit 1 restart</td><td>• Response to RAI B.2.1.33-2(b) dated January 18, 2005</td></tr>
<tr><td>34. Environmental Qualification Program</td><td>Include Unit 1 in the program.</td><td>A.1.35</td><td>Prior to Unit 1 restart</td><td>• LRA Section B.3.1</td></tr>
</table>

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
47. Open Item OI 2.4-3	Perform one time confirmatory UT measurements on the drywell vertical cylindrical area immediately below the drywell flange	N/A	Prior to Unit 1 restart	• Enclosures 1 and 9 or TVA letter dated November 16, 2005
49. Unit 1 Periodic Inspection Program	Develop and implement new program.	A.2.4	Prior to the period of extended operation	• Response to Proposed Unresolved Items 3.0-2 LP (1 & 2) and 3.0-3 LP dated May 27, 2005 • Enclosure 1 of TVA letter dated September 14, 2005
	Develop and submit implementing procedure(s) for NRC review.		At least two years prior to the period of extended operation	• Response to Proposed Unresolved Items 3.0-4 LP dated May 27, 2005
63. Response to NRC Questions Concerning RPV Internals	Replace all BFN Unit 1 dry tubes.	N/A	Prior to Unit 1 restart	• Response to Question (8) dated May 25, 2005
	Perform MSIP for Unit 1 Control Rod Drive Return Line Cap.		Prior to Unit 1 restart	• Response to Question (6) dated May 25, 2005
	Change the Unit 1 AHCs to bolted design.		Prior to Unit 1 restart	• Response to NRC Question (7) dated May 25, 2005

TABLE 3: UNIT 1 RESTART COMMITMENTS THAT ARE DISCUSSED IN LRA APPENDIX F

NOTE: See Note at the beginning of Table 2

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
50. Appendix F.1	Evaluate and modify, as required, main steam leakage path piping to ensure structural integrity.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
51. Appendix F.2	Implement Containment Atmosphere Dilution System modification.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
52. Appendix F.3	Revise Fire Protection Program to ensure compliance with 10 CFR 50 Appendix R. Revise Fire Protection Report per Unit 1 License Condition 2.C.13.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
53. Appendix F.4	Implement Environmental Qualification Program.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
54. Appendix F.5	Address GL 88-01, and make necessary plant modifications.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
55. Appendix F.6	BWRVIP Programs used for Units 2 and 3 will be used for Unit 1.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
56. Appendix F.7	Install ATWS features.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005

TABLE 3: UNIT 1 RESTART COMMITMENTS THAT ARE DISCUSSED IN LRA APPENDIX F

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
57. Appendix F.8	Remove Reactor Vessel Head Spray piping in drywell, and seal the primary containment penetrations	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
58. Appendix F.9	Implement the Hardened Wetwell Vent modification.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
59. Appendix F.10	Cap Service Air and Demineralized Water Primary Containment Penetrations.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
60. Appendix F.11	Modify Auxiliary Decay Heat Removal System to serve Unit 1.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
61. Appendix F.12	Fully implement the Maintenance Rule Unit 1's temporary exemption ceases to be effective.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
62. Appendix F.13	Replace RWCU piping outside of primary containment with IGSCC resistant piping. Implement actions requested in GL 89-10 for RWCU	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005

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 Tennessee Valley Authority (TVA), and other correspondence regarding the NRC staff's reviews of the Browns Ferry Nuclear (BFN), Units 1, 2 and 3 (under Docket Numbers 50-259, 50-260 and 50-296) license renewal application (LRA).

July 12, 1984	TVA letter to NRC, in regards to NUREG 0737, Item II.K.3.28, "Qualification of ADS Accumulators"
July 24, 1985	NRC letter to TVA, "NUREG 0737, Item II.K.3.28, Qualification of ADS Accumulators"
March 1, 1988	TVA letter, R. Gridley to NRC, "Browns Ferry Nuclear Plant (BFN) - Anticipated Transients Without Scram (ATWS) Rule (10 CFR 50.62) - Plant Specific Design"
August 1, 1988	TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) - Response to Bulletin (sic) 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping, dated January 25, 1988"
October 24, 1988	TVA letter, S. A. White to NRC, "Browns Ferry Nuclear Plan (BFN) Nuclear Performance Plan, Revision 2"
December 8, 1988	NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 1, 2 and 3 - Appendix R Safe Shutdown System Analysis"
January 22, 1989	NRC letter to TVA, "Compliance with Rule 10 CFR 50.62 Relating to Alternate Rod Injection and Reactor Pump Trip Systems"
January 26, 1989	NRC letter to TVA, "Technical Specifications on Anticipated Transients Without Scram (ATWS) - Recirculation Pump Trip (RPT), Browns Ferry Nuclear Plants, Units 1, 2, and 3" (Accession No. ML020020476)
October 30, 1989	NRC letter to All Operating Licensees with Mark I Containments, "Installation of a Hardened Wetwell Vent (Generic Letter 89-16)," dated September 1, 1989. 2. TVA letter, M. J. Ray to NRC, "Response to Generic Letter 89-16, Installation of Hardened Wetwell Vent"
November 2, 1989	NRC letter to TVA, "Supplemental Safety Evaluation on Post-Fire Safe Shutdown Systems and Final Review of the National Fire Protection Association Code Deviations - Browns Ferry Nuclear Plant, Unit 2"

November 29, 1990	TVA letter, E. G. Wallace to NRC, “Browns Ferry Nuclear Plant (BFN) - Anticipated Transient Without Scram (ATWS) Response to NRC Followup Items Received During ATWS Inspection
January 23, 1991	NRC letter to TVA, “NUREG 1232, Volume 3, Supplement 2 Browns Ferry, Unit 2"
March 6, 1991	NRC letter to TVA, “Issuance of Amendment” (Accession No. ML020090226)
May 5, 1992	NRC letter to TVA, “Request for Additional Information to Review Compliance with NUREG 0737, Item II.E.4.2 and 10 CFR 50, Appendix J
December 28, 1992	TVA letter to NRC, “Browns Ferry Nuclear Plant – Unit 3 - Supplemental Response to Generic Letter (GL) 88-01, NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping”
March 31, 1993	NRC letter to TVA, “Fire Protection Program - Browns Ferry Nuclear Plant Units 1, 2 and 3"
December 3, 1993	NRC letter to TVA, “Browns Ferry Nuclear Plant Unit 3 - Safety Evaluation of Supplemental Response to Generic Letter 88-01"
January 2, 1995	NRC letter to TVA, “Browns Ferry Nuclear Plant Units 1 and 3, NUREG-0737, Item II.E.4.2, Containment Isolation Dependability”
November 2, 1995	NRC letter to TVA, “Safety Evaluation of Post-Fire Safe Shutdown Capability and Issuance of Technical Specification Amendments for the Browns Ferry Nuclear Plant Units 1, 2, and 3" (Accession No. ML020040025)
April 25, 1997	BWRVIP letter, C. Terry to B. Sheron (NRC), “BWR Utility Commitments to the BWRVIP”
August 9, 1999	NRC letter to TVA, ”Issuance of Temporary Partial Exemption from 10 CFR 50.65, Browns Ferry Nuclear Plant, Unit 1” (Accession No. ML020040329)
November 25, 2002	NRC Meeting Summary, S.T. Hoffman, “Summary Of Meeting to Discuss Planned License Renewal Application” (Accession No. ML023300013)
June 2, 2003	NRC Meeting Summary, S.T. Hoffman, Summary Of Meeting To Discuss Planned License Renewal Application (Accession No. ML031540295)
October 30, 2003	NRC Meeting Summary, S.T. Hoffman, “Summary Of Meeting to Discuss Browns Ferry Units 1, 2, and 3 Planned License Renewal Application” (Accession No. ML033080369)

December 3, 2003	NRC letter to TVA, “Browns Ferry Nuclear Plant Unit 3 - Safety Evaluation of Supplemental Response to Generic Letter 88-01"
December 31, 2003	Letter from Mr. Mark. J. Burzynski, Tennessee Valley Authority (TVA) to the NRC, submitting the application for the renewal of the operating Licenses for Browns Ferry Nuclear Units 1,2, and 3 (Accession No. ML040060361)
January 7, 2004	Letter from P.T.Kuo, NRC, to J.A.Scalice,TVA forwarding the Notice of Receipt and Availability of the application for the renewal of the operating license for the BFN Units 1,2 and 3 (Accession No. ML040090370)
February 19, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC- Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - January 28, 2004 Meeting Follow-Up - Additional Information - Supplemental Information - Unit 1 Wet Lay-Up (Accession No. ML040510241)
March 4, 2004	Letter from P.T.Kuo, NRC to J. A. Scalice, TVA indicating acceptability and sufficiency for docketing and opportunity for a hearing regarding the application from Tennessee Valley Authority for renewal of the operating licenses for the BFN, units 1, 2, and 3 (Accession No. ML040650206)
March 25, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC stating use of the BFN license renewal boundary drawings to obtain scoping results (Accession No. ML040860596)
March 31, 2004	Letter from P.T.Kuo, NRC, to J.A.Scalice,TVA forwarding the review schedule for application for renewal of the operating licenses for the BFN Units 1,2 and 3 (Accession No. ML040910016)
May 4, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the April 7, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML041310015)
May 6, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the March 24, 2004 and March 30, 2004 teleconferences between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML041310029)
May 10, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the April 14, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML041310206)

May 27, 2004	Browns Ferry Nuclear Plant (BFN) Units 1, 2, and 3 - March 30-31, 2004 meeting follow-up-additional information for License Renewal Environmental Review
May 28, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC updating the LRA application sections 4.2 and 4.3 to reflect extended power uprate conditions (Accession No. ML041550393)
June 15, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 19, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700550)
June 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the April 21, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700505)
June 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 27, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) concerning activities on BFN units 1, 2 and 3 LRA. (Accession No. ML041700523)
June 18, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 5, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700572)
June 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.5 of the LRA. (Accession No. ML041760076)
June 28, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 27, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041810168)
July 7, 2005	Response to Request for Additional Information (RAI) regarding severe accident mitigation alternatives for Browns Ferry Nuclear Plant, Units 1, 2, and 3

July 9, 2004	TVA letter to NRC, “Browns Ferry Nuclear Plant (BFN) Unit 1 - Technical Specification (TS) 436 - Increased Main Steam Isolation Valve (MSIV) Leakage Rate Limits and Exemption from 10 CFR 50, Appendix J” (Accession No. ML041980222)
July 10, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the June 16, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML041950508)
July 19, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the April 28, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML042010388)
July 19, 2004	Letter from Mr. M.J.Burzynski, Tennessee Valley Authority (TVA) to the NRC regarding lay-up effects of Unit 1 Structures and Component Supports (Accession No. ML042040231)
July 21, 2004	TVA letter, T. E. Abney to NRC, “Browns Ferry Nuclear Plant (BFN) Unit 1 – Supplemental Response to Generic Letter 88-01, NRC Position on Intergranular Stress Corrosion Cracking in BWR Austenitic Stainless Steel Piping” (Accession No. ML042040274)
July 28, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 1, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff’s review of the LRA. (Accession No. ML042110485)
July 30, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.1 of the LRA. (Accession No. ML042120186)
August 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC detailed explanation of how the LRA application Bounds the BFN extended power uprate (EPU) submittals (Accession No. ML042180449)
August 5, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC update of application sections 4.2 and 4.3 to reflect extended power uprate conditions –supplemental information (Accession No. ML042220285)

August 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 3.1, 3.2, 3.3, and 3.4 of the LRA. (Accession NO. ML042360590)
August 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.3, 3.3, 4.4, B.2.0 of the LRA (Accession NO. ML042360762)
August 23, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 28, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042390497)
August 26, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 24, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042400550)
August 31, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 12, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042450211)
August 31, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.1, 2.2, and 2.3 of the LRA. (Accession No. ML042450260)
September 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit – request for additional information (RAI) (Accession No. ML042520374)
September 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the August 19, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042600522)
September 27, 2004	NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 — Issuance of Amendments Regarding Full- Scope Implementation of Alternative Source Term" (Accession No. ML042730028)

September 30, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit –request for additional information (Accession No. ML042750259)
October 6, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on 2.3.1, 2.3.2, and 2.3.3 of the LRA. (Accession No. ML042860015)
October 8, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit –request for additional information (Accession No. ML042870422)
October 8, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.3 of the LRA. (Accession No. ML042860051)
October 8, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening staff audit at BFN – request for additional information (Accession No. ML042870428)
October 8, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.3.2 and 2.3.3 of the LRA (Accessiion No. ML042860066)
October 12, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.3 of the LRA (Accession No. ML042860133)
October 15, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the September 15, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042920201)
October 18, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit – request for additional information (Accession No. ML042930471)
October 19, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC – request for additional information - Sections 2.1, 2.2, and 2.3, related to the Scoping and Screening: Mechanical Systems (Accession No. ML042930931)

October 21, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the September 22, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042990519)
October 22, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the August 18, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML043000040)
October 25, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - request for additional information on Appendix F (Accession No. ML043000149)
October 28, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Fire Protection Section Verbal Request on October 20, 2004 - Response to NRC Request for Additional Information (Accession No. ML043030434)
November 1, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.5 of the LRA (Accession No. ML043060492)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3 License Renewal Application – Heating, Ventilation, and Cooling (HVAC) Systems Sections 2.3.2 and 2.3.3 – Request for Additional Information (RAI) - (Accession No. ML043090545)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3 License Renewal Application – Reactor Systems Section 2.3.1, 2.3.2, and 2.3.3 – Request for Additional Information (Accession No. ML043100588)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Auxiliary Systems Section 3.3 - Response to NRC Request for Additional Information (Accession No. ML043090343)
November 4, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 3.1.2.4, B.2.1.13, and 4.7.8 of the LRA (Accession No. ML043090573)

November 4, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.6 of the LRA (Accession No. ML043090577)
November 18, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.2 and 3.4 of the LRA (Accession No. ML043270655)
December 1, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.1 of the LRA (Accession No. ML043360401)
December 1, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – electrical and instrument and control systems (I&C) systems section 2.5- Response to NRC Request for Additional Information (Accession No. ML043370173)
December 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Heating, Ventilation, and Cooling (HVAC) Systems Sections 2.3.2 and 2.3.3 - Response to NRC Request for Additional Information (Accession No. ML043380353)
December 7, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Chemistry Control Program, Section B.2.1.5 of the LRA (Accession No. ML043490336)
December 9, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Mechanical Systems Sections 3.1.2.4, B.2.1.13, and 4.7.8- Response to NRC Request for Additional Information (Accession No. ML043440080)
December 9, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Electrical and Instrument and Control Systems (I&C) Systems Section 3.6- Response to NRC Request for Additional Information (Accession No. ML043440226)
December 9, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding status of staff review of the Browns Ferry Nuclear Plant Units 1, 2, and 3 License Renewal Application (Accession No. ML043490470)

December 10, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2, and 3 license renewal application on Section 3.5 and B.2.1.34 of the LRA (Accession No. ML043500140)
December 13, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on ASME Section XI Subsection IWF Program, Section B.2.1.33 of the LRA (Accession No. ML043500210)
December 14, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application Section 4.7.1 of the LRA (Accession No. ML043500508)
December 16, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Mechanical Systems Sections 3.2 and 3.4 - Response to NRC Request for Additional Information (Accession No. ML043520395)
December 16, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application Section 3.0 of the LRA (Accession No. ML043560502)
December 20, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.4-2 Mechanical and Environmental Qualifications - Response to NRC Request for Additional Information (Accession No. ML043550381)
December 20, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Section 2.4 of the LRA (Accession No. ML043560382)
January 6, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections B.2.1.5 Chemistry Control Program - Response to NRC Request for Additional Information (Accession No. ML050070179)
January 7, 2005	Letter from Mr. M. D. Skaggs, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Meeting Summary and Plant Visit (ML050100180)

January 12, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.7.1 Reactor Building Crane Load Cycle - Response to NRC Request for Additional Information (Accession No. ML050130333)
January 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections B.2.1.33 ASME Section XI Subsection IWF Program - Response to NRC Request for Additional Information (Accession No. ML050180505)
January 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.5 and 3.6 Electrical and Instrument and Control - Response to NRC Request for Additional Information (Accession No. ML050180537)
January 20, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.1 Aging of Mechanical Systems During the Extended Outage - Response to NRC Request for Additional Information (Accession No. ML050210334)
January 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.4 - Response to NRC Request for Additional Information (Accession No. ML050250264)
January 25, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 4.4 - Response to NRC Request for Additional Information (Accession No. ML050260327)
January 27, 2005	Letter from Harold O. Christensen, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) regarding Browns Ferry Nuclear Plant - Inspection Report 05000259/2004012, 05000260/2004012, and 05000296/2004012 (Accession No. ML050270022)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Annual Update (Accession No. ML050310428)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – The Integration of Unit 1 Restart and License Renewal Activities. Response to NRC Request for Additional Information (Accession No. ML050320137)

January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.1, 4.2, and B.2.1 Reactor Vessel and Internals Mechanical Systems - Response to NRC Request for Additional Information (Accession No. ML050320145)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.5, 4.7.4, and B.2.1.32 - Response to NRC Request for Additional Information (Accession No. ML050320149)
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February 28, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.1, final status of response to RAI 2.1-2, A.3 - Response to NRC Request for Additional Information (Accession No. ML050600274)
February 28, 2005	Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application - LRA Section 3.5 - response to NRC request for follow-up question for RAI 3.5-7
March 2, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.5 and 4.7.8 - Response to NRC Request for Additional Information (Accession No. ML050620258)
March 3, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Section 4.7.7 of the LRA (Accession No. ML050620592)
March 11, 2005	Letter from Yoira Diaz-Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.1.2.4 and 3.5 of the LRA (Accession No. ML050700309)

March 11, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.3 - Response to NRC Request for Additional Information (Accession No. ML050700463)
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April 5, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.1.2.4-7 and 3.5-16 AMR Small Bore Piping and Fittings and Submerged Reinforced Concrete - Response to NRC Request for Additional Information (Accession No. ML050950311)
April 8, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) Forwarding Request for Additional Information for the Review of the BFN Units 1, 2, and 3 License Renewal Application on Section 2.3.3.21 (Accession No. ML050980086)
April 14, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.4 and 3.5 Radwaste and Service Building - Response to NRC Request for Additional Information (Accession No. ML051040164)
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May 12, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 7.2.5.2 ASME Equivalent Supports and Components - Response to NRC Request for Additional Information (Accession No. ML051330038)
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May 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.0-9 Unit 1 Layup Program - Response to NRC Request for Additional Information (Accession No. ML051390237)
May 19, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference with Tennessee Valley Authority (TVA) License Renewal Staff (Accession No. ML051400190)
May 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.3.3.21 Reactor Water Cleanup System - Response to NRC Request for Additional Information (Accession No. ML051440261)
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May 26, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference with Tennessee Valley Authority (TVA) License Renewal Staff (Accession No. ML051460418)
May 27, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.0 Unit 1 Layup Program - Response to NRC Request for Additional Information (Accession No. ML051470354)
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May 31, 2005	Letter from Mr. M D. Skaggs, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Additional Information (RAI) concerning follow up to RAIs 2.4-3, 3.5-1, 3.5-4, B.2.1.33-1, and B.2.1.36 (Accession No. ML051520084)
May 31, 2005	Letter from M.L. Marshall, Jr., NRC, to K W. Singer, Tennessee Valleu Authority (TVA) - Browns Ferry Nuclear Plant Unit 1 - Safety Evaluation for Relief Request 1-ISI-19 Associated With Reactor Pressure Vessel Circumferential Shell Welds (Accession No. ML051110626)
June 3, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Response to NRC Request for Additional Information on Potential Open Item 3.3.2.35-1 (Accession No. ML051540336)
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June 15, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) for the Time-limited Aging Analysis identified in 4.7.2 and 4.7.5 of LRA (Accession No. ML051660547)
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June 29, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) concerning Follow up to Section 4.7. 7 Time Limited Aging Analysis RAIs (Accession No. ML0519402910)
August 2, 2005	Letter from Yoira Diaz Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference held on July 7, 2005, with Tennessee Valley Authority (TVA) License Renewal Staff, Concerning Information on Browns Ferry Nuclear Plant, Units 1, 2, and 3 License Renewal Application (Accession No. ML052140646)
August 4, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application - Description of Unit 1 Periodic Inspection Program (Accession No. ML052170406)
August 9, 2005	Letter from P.T. Kuo, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Safety Evaluation Report (SER) with Open Items Related to the License Renewal of Browns Ferry Nuclear Plant, Units 1, 2, and 3 (Accession No. ML052210459)
August 9, 2005	Letter from Mr. Brian O’Grady, Browns Ferry Nuclear Plant to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - Consolidated List of Commitments for License Renewal (Accession No. ML052220070)

September 6, 2005	Letter from Mr. Brian O'Grady, Browns Ferry Nuclear Plant to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Response to NRC Request for Additional Information Concerning Follow-Up to RAIs 4.7.7-1 and 4.7.7-2 (Accession No. ML052570462)
September 14, 2005	Letter from Mr. Brian O'Grady, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Results of Review of Safety Evaluation Report (SER) with Open Items Related to License Renewal of Browns Ferry Nuclear Plant (Accession No. ML052630075)
October 31, 2005	Letter from Yoira Diaz Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference held on October 14 and 18, 2005, with Tennessee Valley Authority (TVA) License Renewal Staff, Concerning Information on Browns Ferry Nuclear Plant, Units 1, 2, and 3 License Renewal Application (Accession No. ML053050358)
November 16, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application (LRA) - Supplemental Responses to NRC Requests (Accession No. ML053320331)
November 21, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Clarification for BFN's use of Linde 80 Weld Material on Unit 1. (Accession No. ML053260542)
December 12, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Clarification of Commitment Tables Contained in the Safety Evaluation Report (Accession No. ML053460417)
December 20, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Clarification of Commitment Tables Contained in the Safety Evaluation Report (Accession No. 053560328)

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APPENDIX C
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APPENDIX D

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 Browns Ferry Nuclear Plant, Units 1, 2, and 3, Docket Numbers 50-259, 50-260, and 50-296, respectively.

(1) NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” April 2001

(2) NEI 95-10, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule, Revision 3,” August 2001

(3) NUREG-1801, “Generic Aging Lessons Learned Report (GALL),” April 2001

(4) Browns Ferry Nuclear Plant, Units 1, 2, and 3, updated final safety analysis report (UFSAR), Amendment 20.

(5) BWR Vessel and Internals Project Report BWRVIP-25: “BWR Core Plate Inspection and Flaw Evaluation Guidelines,” TR-107284, December 1996.

(6) BWR Vessel and Internals Project Report BWRVIP-99: “Crack Growth Rates in Irradiated Stainless Steels in BWR Internal Components,” TR-1003018, December 2001.