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BGE

December 17, 1997

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Request for Review and Approval of System Reports for License Renewal

REFERENCES:

(a) Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated August 18, 1995, Integrated Plant Assessment Methodology

(b) Letter from Mr. D. M. Crutchfield (NRC) to Mr. C. H. Cruse (BGE), dated, April 4, 1996, Final Safety Evaluation (FSE) Concerning The Baltimore Gas and Electric Company Report entitled, "Integrated Plant Assessment Methodology"

(c) Letter from Mr. S. C. Flanders (NRC), dated March 4, 1997, "Summary of Meeting with Baltimore Gas and Electric Company (BGE) on BGE License Renewal Activities"

This letter forwards the attached Integrated Plant Assessment (IPA) System Reports for review and approval in accordance with 10 CFR Part 54, the license renewal rule. Should we apply for License Renewal, we will reference IPA System Reports as meeting the requirements of 10 CFR 54.21(a), "Contents of application-technical information," and the demonstration required by 10 CFR 54.29(a)(1), "Standards for issuance of a renewed license."

The information in this report is accurate as of the dates of the references listed therein. Per 10 CFR 54.21(b), an amendment or amendments will be submitted that identify any changes to the current licensing basis that materially affect the content of the license renewal application.

In Reference (a), Baltimore Gas and Electric Company submitted the IPA Methodology for review and approval. In Reference (b), the Nuclear Regulatory Commission (NRC) concluded that the IPA

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Methodology is acceptable for meeting 10 CFR 54.21(a)(2) of the license renewal rule, and if implemented, provides reasonable assurance that all structures and components subject to an aging management review pursuant to 10 CFR 54.21(a)(1) will be identified. Additionally, the NRC concluded that the methodology provides processes for demonstrating that the effects of aging will be adequately managed pursuant to 10 CFR 54.21(a)(3) that are conceptually sound and consistent with the intent of the license renewal rule.

In Reference (c), the NRC stated that if the format and content of these reports met the requirements of the template developed by BGE, the NRC could begin the technical review. This report has been produced and formatted in accordance with these guidance documents. We look forward to your comments on the reports as they are submitted and your continued cooperation with our license renewal efforts.

Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

Charles H. Cruse

STATE OF MARYLAND :
: **TO WIT:**
COUNTY OF CALVERT :

I, Charles H. Cruse, being duly sworn, state that I am Vice President, Nuclear Energy Division, Baltimore Gas and Electric Company (BGE), and that I am duly authorized to execute and file this response on behalf of BGE. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other BGE employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Charles H. Cruse

Subscribed and sworn before me, a Notary Public in and for the State of Maryland and County of St. Mary's, this 17 day of December, 1997.

WITNESS my Hand and Notarial Seal: Laura A. Martin
Notary Public

My Commission Expires: December 17, 1997
Date

LAURA A. MARTIN
NOTARY PUBLIC STATE OF MARYLAND
My Commission Expires July 1, 1998

CHC/DLS/dlm

Attachments: (1) 4.1 Reactor Coolant System
(2) 5.11A Auxiliary Building Heating and Ventilation System
(3) 5.16 Saltwater System

cc: R. S. Fleishman, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
A. W. Dromerick, NRC
D. L. Solorio, NRC
H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR
J. H. Walter, PSC

ATTACHMENT (1)

APPENDIX A - TECHNICAL INFORMATION

4.1 - REACTOR COOLANT SYSTEM

4.1 Reactor Coolant System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Reactor Coolant System (RCS). The RCS was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

4.1.1. Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools that capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the component types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 4.1.1.1 presents the results of the system level scoping, 4.1.1.2 the results of the component level scoping, and 4.1.1.3 the results of scoping to determine components subject to AMR.

Representative historical operating experience pertinent to aging is included in appropriate areas, to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

4.1.1.1 System Level Scoping

This section begins with a description of the system that includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within scope for license renewal.

<u>System Description/Conceptual Boundaries</u>

The function of the RCS is to remove heat from the reactor core and internals and transfer it to the secondary (steam generating) system. The RCS of each Unit, which is entirely located within the Containment Building, consists of two heat transfer loops connected in parallel across the reactor pressure vessel (RPV). Each loop contains one steam generator (SG), two reactor coolant pumps (RCPs), connecting piping, and flow and temperature instrumentation. Other major RCS components include the pressurizer and quench tank. Coolant system pressure is maintained by the pressurizer, which is connected to one of the RCS loop hot legs. [Reference 1, Section 4.1.2] Because the RPV is such a significant component of the RCS and because several aging mechanisms are unique to it, the RPV has a separate aging management evaluation in Section 4.2 of the BGE LRA.

The basic RCS functional requirements are: [Reference 2, Section 1.1.3]

- To remove heat from the reactor core and reactor internals and transfer it to the secondary (SGs) system;
- To contain fission products released by fuel element defects and prevent the release of these fission products to the environment;
- To provide remote monitoring capability for the RCS parameters;
- To permit remote control of RCS parameters; and
- To provide required inputs to the Reactor Protective System, the Reactor Regulating System, and the Engineered Safety Features Actuation System for protection of the reactor core and RCS components.

The primary function of the RCPs is to provide forced coolant flow through the core. There are four RCPs in the RCS of each Unit, which are located in the SG (return lines) "cold legs." [Reference 1, Section 4.1.3]

During operation, the four RCPs in each Unit circulate water through the RPV where the water serves as both coolant and neutron moderator for the core. The heated water enters the two SGs in each Unit, transferring heat to the secondary (steam) system, and then returns to the RCPs to repeat the cycle. Refer to Figure 4-1 (Unit 1) and Figure 4-17 (Unit 2) of the Updated Final Safety Analysis Report (UFSAR) for a flow diagram of the RCS. [Reference 1, Section 4.1.2]

The RCS pressure is maintained by regulating the water temperature in the pressurizer where steam and water are held in thermal equilibrium. Steam is either formed by the pressurizer heaters or condensed by the pressurizer spray to limit the pressure variations caused by contraction or expansion of the reactor coolant. The pressurizer is located with its base at a higher elevation than the RCS loop piping. [Reference 1, Section 4.1.2] A number of pressurizer heaters are operated continuously to offset the heat losses and the continuous minimum spray, thereby maintaining the steam and water in thermal equilibrium at the saturation temperature corresponding to the desired system pressure. [Reference 1, Section 4.1.3]

Overpressure protection is provided by two power-operated relief valves (PORVs) and two spring-loaded safety valves connected to the top of the pressurizer. Steam discharged from the valves is cooled and condensed by water in the quench tank. The RCS vent lines from the RPV and the pressurizer also discharge to the quench tank. In the unlikely event that the discharge exceeds the capacity of the quench tank, the tank is relieved to the containment via the quench tank rupture disc. The quench tank is located at a level lower than the pressurizer. This ensures that any PORV or pressurizer safety valve leakage from the pressurizer, or any discharge from these valves, drains to the quench tank. [Reference 1, Section 4.1.2]

The Nuclear Steam Supply System (NSSS) utilizes two SGs to transfer the heat generated in the RCS to the secondary system. The SG shell is constructed of carbon steel. Manways and handholes are provided for easy access to the SG internals. [Reference 1, Section 4.1.3]

The SG is a vertical U-tube heat exchanger. The SG operates with the reactor coolant in the tube side and the secondary fluid in the shell side. Reactor coolant enters the SG through the inlet nozzle, flows through 3/4" outside diameter U-tubes, and leaves through two outlet nozzles. Vertical partition plates in the lower head separate the inlet and outlet plenums. The plenums are stainless steel clad, while the primary side of the tube sheet is nickel-chromium-iron (Ni-Cr-Fe) clad. The vertical U-tubes are Ni-Cr-Fe alloy. The tube-to-tube sheet joint is welded on the primary side. Tubes that have degraded may be repaired using tube sleeves or removed from service by either a welded or a mechanical-type tube plug. [Reference 1, Section 4.1.3]

Feedwater enters the SG through the feedwater nozzle where it is distributed via a feedwater distribution ring. Water exits the ring through apertures in the top fitted with J-tubes, then flows into the downcomer. The downcomer is an annular passage formed by the inner surface of the SG shell and the cylindrical shell wrapper that encloses the vertical U-tubes. At the bottom of the downcomer, the secondary water is directed upward past the vertical U-tubes where heat transfer from the primary side produces a water-steam mixture. [Reference 1, Section 4.1.3.2]

Constant RCS makeup and letdown is handled by the Chemical and Volume Control System (CVCS). An inlet nozzle on each of the four RPV inlet pipes allows injection of borated water into the RPV from the CVCS and from Safety Injection System in the event emergency core cooling is needed. During a normal plant shutdown, these nozzles are also used to supply shutdown cooling flow from the low pressure safety injection pumps. An outlet nozzle on one RPV outlet pipe is used to remove shutdown cooling flow. [Reference 1, Section 4.1.2]

Drains from the RCS piping to the Radioactive Waste Processing System are provided for draining the RCS for maintenance operations. A connection is also provided on the quench tank for draining it to the Radioactive Waste Processing System following a relief-valve or safety-valve discharge. [Reference 1, Section 4.1.2]

The RCS piping consists of two loops that connect the SGs to the reactor vessel. Each loop consists of 42-inch inside diameter "hot leg" piping connecting the reactor vessel outlets to the SG inlets, and 30-inch inside diameter piping connecting the SG outlets to the RCPs and the coolant pumps to the reactor vessel inlet nozzles. A surge line connects one loop hot leg to the pressurizer. [Reference 1, Section 4.1.2]

Vents were added to the RPV head and to the pressurizer head in response to the Three Mile Island lessons learned report, "Clarification of TMI Action Plan Requirements," NUREG 0737, Item II.B.1. These vents are intended to provide a means of releasing non-condensable gases from the RCS during natural circulation. The pressurizer vent line valves are used as a backup to main and auxiliary spray to depressurize the RCS during a SG tube rupture. The original design of CCNPP allowed venting of the RCS only during cold shutdown. The vent modifications provide electrically-operated solenoid valves, powered from emergency electrical busses, that are operated from the Control Room. The RPV and the pressurizer each have two of these valves in series, which fail closed (power-to-open). The reactor vessel vent line valves are installed in previously existing lines; the pressurizer vent line valves are installed in a line that was added as an additional branch off the pressurizer vapor sample line. The two vent lines join to a common line that leads to the quench tank. The common line contains a temperature element and alarm that is used for valve seat leak detection and flow indication. [Reference 1, Section 4.1.3]

The components covered by this evaluation include the RCPs and their motors, RCS piping, pressurizer, pressurizer heaters, PORVs and safety valves, SGs, quench tank, and associated instruments and controls. The SG boundaries are set at the ends of the nozzles' safe-ends connecting the SG to other components or systems. The nozzles include main feedwater, auxiliary feedwater, main steam, RCS inlet and outlet, instrumentation, and any integral attachments. [Reference 2, Section 1.1.2]

The boundary between the RPV and RCS main coolant piping excludes the RPV nozzles, which are evaluated with the RPV and Control Element Drive Mechanisms (CEDMs)/Electrical System in Section 4.2 of the BGE LRA. [Reference 2, Section 1.1.2]

In addition, the following piping, supports, instrumentation and controls, and valves are covered or excluded in this evaluation: [Reference 2, Section 1.1.2]

Piping:

- Small tubing and piping that is field run (i.e., instrumentation tubing) and does not have component designators is not evaluated in this report;
- PORV and safety valve discharge piping is included up to but not including the connecting nozzles on the quench tank;
- Vents, drains, and other similar attached lines are included out to the second valve from the RCS; and
- Safety injection and similar lines from the interconnecting systems are included out to the first valve from the RCS.

Supports and hangers for piping and components that are not reviewed in this evaluation are evaluated in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.

Instrumentation and Controls covered by this evaluation are: [Reference 2, Section 1.1.2]

- All remote and local instrumentation associated with the RCS loops, the pressurizer, and the RCPs. Steam generator secondary side instrumentation is not covered in this evaluation;
- Incore neutron detectors and incore (core exit) temperature monitors;
- Instrumentation scope includes transmitters, signal processing, equipment, Control Room displays, and other applicable readouts, but does not include cabling. Cabling is evaluated in the Cables Commodity Evaluation in Section 6.1 of the BGE LRA;
- Automatic and manual controls for pressurizer heaters, pressurizer spray, RCPs, and the PORV and its isolation valves are evaluated; and
- Power supply components for the RCPs and heaters are included up to the power supply breaker.

The valves covered by this review include: [Reference 2, Section 1.1.2]

- Valves associated with the pressurizer spray (including Instrument Air System supply valves to the pressurizer spray control valves);
- Pressurizer Code safety valves;
- PORV and associated motor operated block valves;
- All normally closed RCS pressure boundary valves in vent and drain lines (this extends to the second valve from the RCS in each line); and
- Instrument valves for the RCS instrumentation (e.g., pressurizer level transmitter instrument root valves).

In addition, a few valves in associated systems are included; these are: [Reference 2, Section 1.1.2]

- Two manual valves in the CVCS letdown line;
- Check valves in the CVCS RCP seal bleedoff lines;
- Two check valves in the relief piping from the RCS drain tank heat exchanger;
- The air system valves noted above; and
- RCP lube oil reservoir level transmitter root valves.

The RCP and motors and their oil lift system are included in this evaluation. The RCP and motor cooling subcomponents are included in this evaluation out to the connection with the Component Cooling (CC) System. [Reference 2, Section 1.1.2] Included in this evaluation are the SG and pressurizer supports. Component supports, cables, instrument lines, and instruments not identified as RCS components in the RCS scoping results are generically included in the Component Supports Commodity, Cables Commodity, Instrument Lines Commodity and Fire Protection AMRs. [Reference 2, Section 3.2]

System Operating Experience

The following are RCS operating experiences related to aging mechanisms with the potential for affecting the intended functions of the system components.

RCP Events

RCP Suction Deflector Failures

In 1988 and 1996, failures of RCP suction deflector bolting at CCNPP occurred and bolt fragments were assumed to be lodged in the RPV on the vessel cladding and near the downcomer. Refer to the RPV/CEDMs and Electrical System evaluation in Section 4.2 of the BGE LRA for further discussion of this event. [References 3 and 4]

RCP Leakage

On several occasions, CCNPP has shut down due to RCS leakage associated with the RCPs. These occurred primarily between 1978 and 1985, and resulted from minor leakage in RCP sensing, instrument, and controlled leakoff lines. These small RCP lines were leaking at weld locations as the result of vibratory fatigue. Corrective actions have included weld repair and replacement of welded pipe with new continuous sections of pipe for leakoff lines. In some instances the pipe supports were modified to reduce the effects of vibration. Braided hose jumpers were used with sensing and instrument lines. For piping associated with the RCP seal leakoff lines, CCNPP has implemented a vibration monitoring and reduction program, minimized vibration through continued RCP balancing, and replaced/relocated existing pipe flanges. [References 5 through 11]

The original Byron Jackson seals have been replaced with improved seals. The new seals are designed in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, 1983 Edition with Summer 1983 Addenda, and manufactured by Sulzer Bingham Pumps. [Reference 1, Section 4.1]

RCP Thermal Barrier Housing Cracks

Baltimore Gas and Electric Company has determined that NRC Information Notice 97-31, "Failures of Reactor Coolant Pump Thermal Barriers and Check Valves in Foreign Plants," is applicable to CCNPP, since there has been evidence of cracking in the RCP thermal barrier housings. Calvert Cliffs found shallow surface cracking on the 22B RCP thermal barrier housing in 1987. A safety analysis addressed the consequences of this cracking and the potential for overpressurizing the Component Cooling (CC) System. The analysis found that the CC System would not be subjected to overpressurization since there are six CC relief valves with adequate capacity inside the Containment Building. Another analysis by the pump vendor found that any cracks would be self-arresting and would go no deeper. This analysis was partially validated by CCNPP when No. 11B RCP cover was tested in the fall of 1996. The inspection found shallow surface cracks within a small area of oxide that were not evident after the oxide area was cleaned. The cover of No. 21A RCP was also inspected in June 1997, with no cracking found. The potential for thermal stress cracking in the RCPs has also been addressed by adding inspection requirements to the RCP overhaul procedures. Baltimore Gas and Electric Company has concluded that these analyses, tests, and inspection requirements adequately address the concerns of Information Notice 97-31.

Pressurizer Events

Calvert Cliffs has experienced RCS pressure boundary leakage of Alloy 600 components. During the 1989 Unit 2 refueling outage, CCNPP personnel discovered evidence of RCS leakage from approximately 20 of 120 pressurizer heater sleeves. Unit 1 was shut down from 100% power to allow inspection of the pressurizer. No signs or evidence of leakage was found on the Unit 1 pressurizer heater penetrations or pressure/level instrumentation penetrations. Both units remained shut down until the cause was understood.

The cracks were of an axial nature and eventually determined to be not safety significant. [Reference 12] Upon further evaluation it was determined that the cause of the leakage was primary water stress corrosion cracking (PWSCC). Primary water SCC is stress corrosion cracking (SCC) that occurs in susceptible materials exposed to the primary water environment of the RCS. [Reference 13] Calvert

Cliffs has a total of 244 Alloy 600 penetrations in the Unit 1 RCS, and 126 remaining in Unit 2 (120 pressurizer heater sleeves were replaced with Alloy 690 in 1989-1990). In addition, a pressurizer vapor space instrument nozzle was found leaking in May 1989, which led to the replacement of all four of the Unit 2 pressurizer vapor space nozzles with Alloy 690. During the Unit 1 1994 refueling outage, two other heater sleeves were found leaking and were plugged. The remaining 188 heater sleeves were nickel-plated, as a preventive method to halt PWSCC. These events contributed to the development and evaluation of the CCNPP Alloy 600 Program Plan, which manages PWSCC in the RCS. [Reference 14, Sections 1, 2, 3, 18, 19]

SG Events

The CCNPP SGs have been repeatedly and extensively examined with different non-destructive examinations techniques. These non-destructive examination techniques include eddy current testing (bobbin coil examinations, and the Motorized Rotating Pancake Coil and Plus Point system). These examinations found some SG tubes that have degraded due to intergranular stress corrosion cracking (IGSCC), which is the result of material stress, environment, and age. The results of these SG inspection reports are submitted to the NRC. [References 15 and 16] Another degradation mechanism includes denting of the SG tubes. Denting has occurred on numerous tubes and may cause them to eventually crack. Currently, all tubes with cracks are repaired upon detection of the crack. [Reference 17]

To minimize denting, Calvert Cliffs has removed major copper sources from the feedwater and condensate systems and maintained a low oxygen level with secondary chemistry control. [Reference 17] There has also been circumferential cracking of the SG tubes at the hot leg tube sheet expansion transition. All tubes with circumferential cracking are removed from service. The aging mechanism was determined to be IGSCC originating on the secondary side (outer diameter) of the tubes. Calvert Cliffs maintains elevated pH chemistry on the SG secondary side to limit iron transport to the SGs and, therefore, the deposits in the SG. Steam generator deposits create local chemistry conditions conducive to intergranular attack (IGA)/IGSCC. [References 15 and 16]

The primary degradation mechanism of both Unit 1 and 2 SGs is outside diameter initiated IGA/IGSCC. Unit 1 degradation is primarily located in the hot leg upper tube bundle freespan and the hot leg tubesheet transition zone. Unit 2 degradation is primarily located at the hot leg tubesheet transition zone. Baltimore Gas and Electric has pulled several tubes containing stress corrosion cracks from these zones and burst tested them to near virgin tube pressures to show significant margin to structural integrity limits. Baltimore Gas and Electric has also performed in situ pressure tests on degraded tubes to demonstrate adequate structural integrity consistent with the requirements of Regulatory Guide 1.121.

Baltimore Gas and Electric Company is aware of SG flow-assisted corrosion at the San Onofre Nuclear Generating Station and will monitor industry activity related to this aging mechanism. Calvert Cliffs will respond to any NRC generic communications on this matter as part of the CLB. An evaluation of flow-assisted corrosion for CCNPP SGs will be incorporated into annual updates of the BGE LRA.

Other RCS Events

RCS Resin Intrusion

Calvert Cliffs Unit 1 had a resin intrusion in March 1989, and Unit 2 suffered a resin intrusion in January 1983, due to a failed outlet retention element of the ion exchanger in the purification system.

The effect on the RPVs was evaluated at the time of the intrusions, as discussed in Section 4.2 of the BGE LRA, and found to be acceptable. Resin intrusions are a potential issue since resin decomposition products (sulfates) may contribute to cracking of sensitized Alloy 600, and the Unit 1 resin intrusion event caused elevated sulfate levels in the RCS. The Unit was shut down to restore chemistry. The sulfate concentration in the RCS was evaluated by Combustion Engineering (CE) and BGE, and the potential increase for PWSCC or IGSCC was determined to be insignificant. [References 18 and 19]

Boric Acid Corrosion

There have been several instances of external corrosion on RCS components due to boric acid leakage. In 1981, CCNPP Unit 2 experienced boric acid wastage on the RCS cold leg near the suction pipe to an RCP. This wastage (determined to be general corrosion) penetrated to a maximum depth of 1/8 inch (nominal pipe wall thickness 3.6 inches) and extended about 20 percent around the circumference of the pipe. Inservice examination also revealed corrosion damage on the closure studs of two of the four RCPs. [Reference 20] A modification was made to install a stainless steel skirt on the RCPs to prevent any potential borated water leakage from dripping onto the RCS cold leg piping.

RCS Chemistry

An incident related to RCS plant chemistry occurred in October 1979 when an abnormally high ingress of oxygen occurred. This oxygen ingress resulted in an increase of corrosion products in the RCS and eventually to buildup of corrosion products on core surfaces. This corrosion product buildup resulted in axial power imbalance (the corrosion products were a neutron absorber) and a slight increase in the differential pressure drop across the core. This power imbalance led to a 50% power reduction. The source of the oxygen ingress was found and terminated. Calvert Cliffs treated the RCS with hydrogen peroxide during a cold shutdown of the Unit and significant corrosion product releases were observed. Upon return to power, core differential pressure and axial power distribution returned to normal. No fuel failures were observed because of this event. [Reference 21]

RPV Head Closure Seal Leakage Detection Line

Stress corrosion cracking was discovered in 1994 during a metallurgical examination of the Unit 2 RPV head closure seal leakage detector instrument line. Leakage from the line was noted during a routine post-trip containment inspection. The pipe was replaced and an examination confirmed that the failure mechanism was transgranular SCC (TGSCC) of stainless steel. Baltimore Gas and Electric Company concluded that the most likely initiator of the TGSCC was an ever increasing concentration of contaminants in the vicinity of the cracking due to repeated boil off of the liquid left in the line at the end of each refueling, eventually reaching levels high enough to cause TGSCC. [Reference 22] Even though the flawed portion of the line on Unit 2 was replaced during the January 1994 shutdown, BGE replaced the entire pipe during the 1994 refueling outage. Baltimore Gas and Electric Company also conducted non-destructive examination of the Unit 1 RPV head closure seal leakage detector instrument line and discovered flaw indications. As a result, the entire line was replaced and rerouted to an alternate flange tap. To prevent recurrence of TGSCC in the RPV head closure seal leakage monitor lines, BGE currently intends to drain the line after each refueling outage to eliminate liquid/vapor interface in high temperature sections of the line, and remove contaminants that create an environment conducive to TGSCC. [References 22 and 23]

In summary, these RCS events demonstrate that CCNPP has and will continue to address and perform corrective actions as required so that the RCS components are capable of performing their intended function under all current licensing basis (CLB) design loading conditions during the period of extended operation.

System Interfaces

The major RCS interfaces are with the CVCS, Safety Injection System, Reactor Protective System, Reactor Regulating System, Engineered Safety Features Actuation System, NSSS sampling, and the RPVs/CEDMs. Other interfaces include CC, Main Steam, Feedwater, and Auxiliary Feedwater Systems. A simplified flow diagram of the RCS and its interfacing systems and components is provided in Figure 4.1-1. [Reference 1, Figures 4-1, 4-17, Reference 2, Section 1.1.2, Reference 24]

Those systems or systems' components interfacing with the RCS that are within the scope of license renewal are noted with an asterisk (*) in Figure 4.1-1. Where a system, component, commodity, or structure interface is in scope for license renewal, it will be addressed by the respective section of this application for that system, component, commodity, or structure.

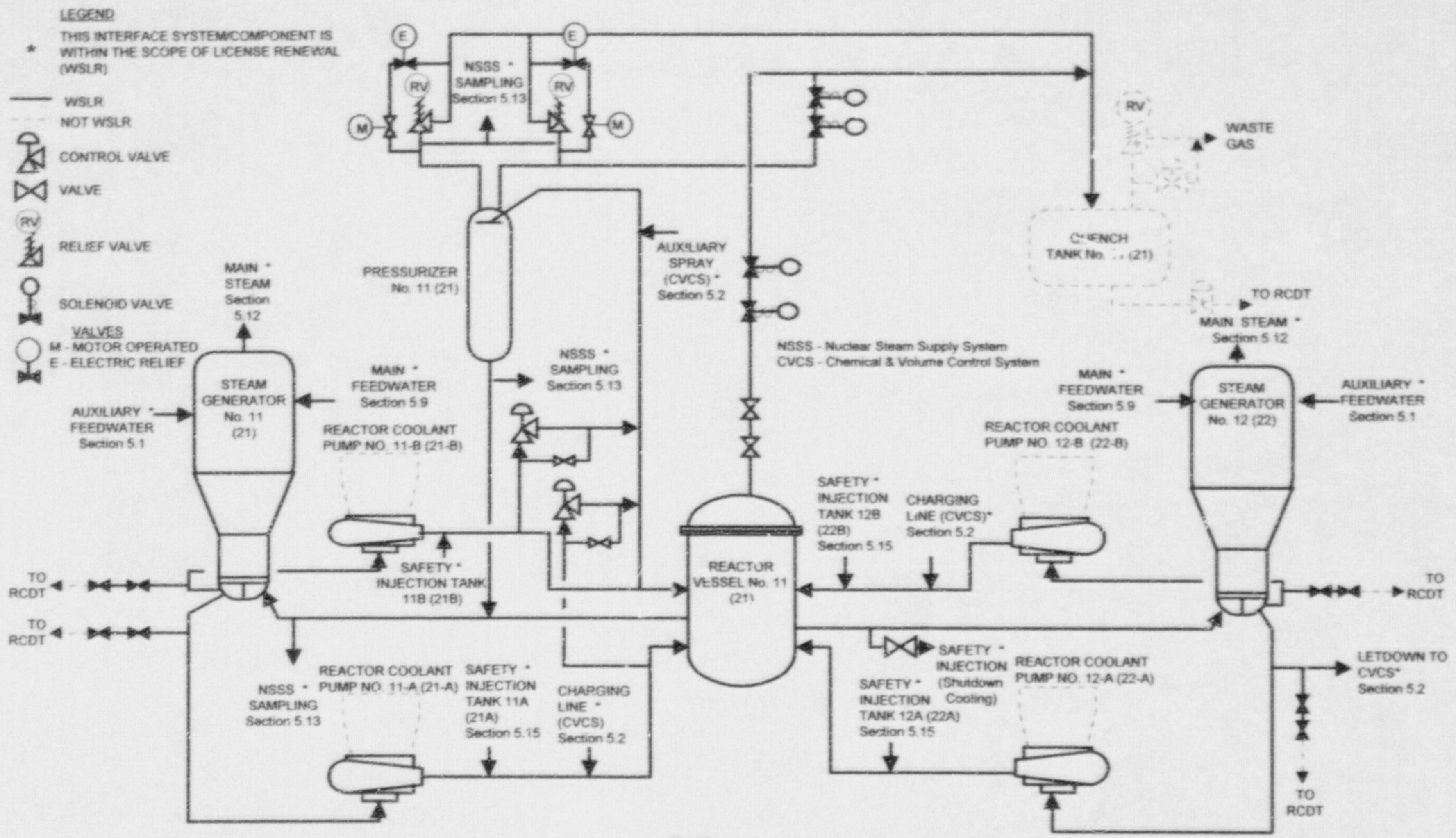

FIG. 4.1-1
UNIT No. 1 REACTOR COOLANT SYSTEM
SIMPLIFIED DIAGRAM
(INFORMATION ONLY)

System Scoping Results

The RCS components are within scope for license renewal based on 10 CFR 54.4(a). In accordance with Section 4.1.1 of the CCNPP IPA Methodology, a detailed list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2): [Reference 25, Table 1]

- To provide manual control of RCS pressure and pressurizer level via charging pumps during design bases events;
- To control RCS pressure by regulating water temperature in the pressurizer;
- To provide indication of degrees of subcooling during design basis events;
- To provide wide range loop temperature signals via resistance temperature detector circuits;
- To provide thermal margin/low pressure signals to the Reactor Protective System for thermal margin/low pressure trip;
- To provide coastdown flow on interruption of power to the RCPs;
- To vent the RCS when natural circulation flow has been disrupted or blocked by accumulation of non-condensable gases;
- To provide differential pressure signals to the Reactor Protective System for low flow trip;
- To provide valve operation logic signals to support Safety Injection System functions;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil);
- To provide containment isolation of the RCS during a loss-of-coolant accident;
- To provide reactor core decay heat removal via natural circulation. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide indication of natural circulation flow via core exit thermocouples. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide reactor vessel coolant inventory level indication. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);
- To provide protection from overpressure in the RCS. Note: This function also applies to station blackout (10 CFR 50.63) based on §54.4(a)(3);

The following RCS intended functions were determined based on the requirements of 10 CFR 54.4(a)(3): [Reference 25, Table 1, TPR Section]

- For station blackout (§50.63) - To detect leakage from the primary system following loss of AC power;
- For station blackout (§50.63) and fire protection (§50.48) - To provide RCS isolation to maintain inventory following loss of AC power;

- For post-accident monitoring - To provide information used to assess the environs and plant conditions during and following an accident;
- For environmental qualification (§50.49) - To maintain functionality of electrical components as addressed by the Environmental Qualification Program;
- For fire protection (§50.48) - To provide lube oil collection for RCP motors sized to accommodate the largest potential oil leak;
- For fire protection (§50.48) - To provide monitoring of essential parameters for ensuring safe shutdown in the event of a postulated severe fire;
- For fire protection (§50.48) - To provide RCS heat removal by realignment and operation of the shutdown cooling flowpath;
- For fire protection (§50.48) - To control RCS pressure by regulating pressurizer water temperature during shutdown in the event of a postulated severe fire.

The design parameters for each of the major RCS components are given in Section 4.1.3 of the CCNPP UFSAR. The RCS is designated as a Category I system for seismic design and a Class 1 system for the criteria of load combinations and stress that are presented in Tables 4-6, 4-7, and 4-8 of CCNPP UFSAR Section 4.1.3. The regulations listed in 10 CFR 54.4(a)(3) do not necessarily require nuclear safety grade components in order to respond to the requirements of the regulations. However, the components of the RCS that have intended functions listed above associated with these regulations are safety-related, Seismic Class 1, and are subject to the applicable loading conditions identified in UFSAR Section 4.1.3, Table 4-8.

4.1.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the RCS that is within the scope of license renewal includes piping, components (e.g., heat exchangers, pressure vessels, pumps, valves, tanks, etc.), and instrumentation that are relied on for mitigation of design basis events, station blackout, post-accident monitoring, environmental qualification, and fire protection.

A total of 63 device types within the RCS equipment types were designated as within the scope of license renewal based on these intended functions. These device types are listed in Table 4.1-1. [Reference 25]

Several components are common to many plant systems and perform the same passive functions regardless of system. These components include the following:

- Structural supports for piping, cables and components;
- Electrical cabling; and
- Process and instrument tubing, instrument tubing manual valves, and tubing supports.

TABLE 4.1-1
RCS DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description	Device Code	Device Description
-CC	Pipe Line with Piping Code of "CC"	PC	Pressure Controller
-GC	Pipe Line with Piping Code of "GC"	PDT	Differential Pressure Transmitter
-HB	Pipe Line with Piping Code of "HB"	PI	Pressure Indicator
-HC	Pipe Line with Piping Code of "HC"	PIA	Pressure Indicator, Alarm
AE	Analyzer Element	PIC	Pressure Indicator Controller
AI	Analyzer Indicator	PNL	Panel
BKR	Circuit Breaker	PR	Pressure Recorder
CKV	Check Valve	PT	Pressure Transmitter
COIL	Electric Coil	PUMP	Pump
CV	Control Valve	PY	Pressure Relay
EI	Voltage/Current Device	PZV	Pressure Vessel
ERV	Electronically-Operated Relief Valve	RI	Radiation Indicator
FU	Fuse	RV	Relief Valve
HS	Hand Switch	RY	Relay
HV	Hand Valve	SV	Solenoid Valve
HX	Heat Exchanger	TE	Temperature Element
I/I	Current/Current Device	TI	Temperature Indicator
II	Ammeter	TK	Tank
JL	Power Lamp Indicator	TP	Temperature Test Point
LC	Level Controller	TR	Temperature Recorder
LG	Level Gauge	TT	Temperature Transmitter
LI	Level Indicator	TY	Temperature Relay
LIC	Level Indicating Controller	U	Heater
LR	Level Relay	VE	Vibration Element
LT	Level Transmitter	VI	Vibration Indicator
LY	Level Relay	VIA	Vibration Indicating Alarm
M/P	Microprocessor	VT	Vibration Transmitter
MD	125/250 VDC Motor	XL	Miscellaneous
MH	13kV Motor/Machine	YX	Power Supply
MOV	Motor-Operated Valve	ZL	Position Indicating Lamp
NB	480 V Local Control Station	ZS	Position Switch
PA	Pressure Alarm		

4.1.1.3 Components Subject to AMR

This section describes the components of the RCS that are subject to an AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or evaluated for aging management in this section

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following RCS functions were determined to be passive. [Reference 25, Attachments 1]

- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil);

- To maintain electrical continuity and/or provide protection of the electrical system; and
- To provide containment isolation of the RCS during a loss-of-coolant accident.

Device Types Subject to AMR

The components of the RCS and their supports were reviewed and those that have the passive intended functions were identified. Of the 63 device types identified within scope for license renewal: [Reference 2, Table 3-2]

- The RPVs and their supports are evaluated for the effects of aging in the RPVs and CEDMs/Electrical System Evaluation in Section 4.2 of BGE's LRA. [The device type PZV evaluated is the pressurizer.]
- One device type, the TE pressure wells, were considered to be part of the pipe and were evaluated with the piping.
- One device type, TPs, or Reactor Vessel Level Monitoring System probes, are evaluated for the effects of aging in the RPV and CEDMs/Electrical System Evaluation in Section 4.2 of BGE's LRA.
- Five device types, LT, PT, PI, PIA, and PDT, are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of BGE's LRA.
- One device type, PNL, is evaluated in the Electrical Commodities Evaluation in Section 6.2 of BGE's LRA.
- Some of the LT and PT device types are subject to replacement (environmental qualification).
- Thirty-nine device types; AE, AI, BKR, COIL, EI, FU, [illegible], I/I, II, JL, LC, LI, LIC, LR, LY, M/P, MD, MH, NB, PA, PC, PIC, PR, PY, RI, RY, TI, TR, [illegible] U, VE, VI, VIA, VT, XL, YX, ZL, and ZS are only associated with active functions.

The 16 remaining device types have passive intended functions and are long-lived. The device types are listed in Table 4.1-2. They are subject to AMR (RCS), and are the subject of the remainder of this report.

Several components in the RCS are common to many plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 1.1.3]

- Those structural supports for piping, cables, components in the RCS that are subjected to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA, except for the SG supports and pressurizer support skirts that are evaluated in this section.
- Electrical cabling for components in the RCS that are subject to AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the RCS passive intended function, "To maintain electrical continuity and/or provide protection of the electrical system."

- Instrument tubing and piping, and the associated supports, instrument valves, and fittings for components in the RCS that are subject to AMR, and the pressure boundaries of the instrument themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

As a result of the evaluations described above, the only passive intended function associated with the RCS is the following:

- To maintain the pressure boundary of the system (liquid and/or gas for five process fluids, RCS primary side, Feedwater/Main Steam secondary side, CC System, and RCP lube oil); and
- To provide containment isolation of the RCS during a loss-of-coolant accident.

The containment isolation function requires maintaining pressure boundary of components that are not contiguous with the RCS safety-related pressure boundary. The two pressure boundary hand valves for sampling the pressurizer quench tank form a portion of the containment isolation function. The remaining sampling components are located in the NSSS Sampling Evaluation in Section 5.13 of the BGE LRA. [Reference 25, Attachments 1]

TABLE 4.1-2

RCS DEVICE TYPES REQUIRING AMR

Piping (-CC)
Piping (-GC)
Piping (-HB)
Piping (-HC)
Check Valve (CKV)
Control Valve (CV)
Electronically-Operated Relief Valve (ERV)
Hand Valve (HV)
Heat Exchanger (HX)
Level Gauge (LG)
Motor-Operated Valve (MOV)
Pump (PUMP)
Pressure Vessel (PZV)
Relief Valve (RV)
Solenoid Valve (SV)
Tank (TK)

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period are not subject to AMR.

4.1.2 Aging Management

The potential ARDMs for the RCS components are listed in Table 4.1-3. The plausible ARDMs are identified in the table by a check mark (✓) in the appropriate column. The device types listed in Table 4.1-3 are those previously identified in Table 4.1-2 as passive and long-lived. The device types not included in Table 4.1-3 were previously dispositioned with the CCNPP IPA Methodology as performing an active function, are replaced and/or addressed in commodity evaluations. For efficiency in presenting the results of these evaluations in this report, the components are grouped together based on similar ARDMs. [Reference 2, Section 4.4]

The following discussions present information on plausible ARDMs. The discussions are grouped by ARDMs and address the materials and environment pertinent to the ARDM, the aging effects for each plausible ARDM, the device types that are affected by each, the methods to manage aging, the aging management program(s), and the aging management demonstration. The groups addressed are:

Group 1 - Denting
Group 2 - Wear
Group 3 - Erosion/Erosion Corrosion
Group 4 - Fatigue
Group 5 - Galvanic /General Corrosion and Pitting
Group 6 - IGA
Group 7 - SCC/IGSCC/PWSCC
Group 8 - Thermal Embrittlement

TABLE 4.1-3
POTENTIAL AND PLAUSIBLE ARDMs FOR THE RCS

	Device Type																
Potential ARDM Name	-CC	-GC	-HB	-HC	CKV	CV	ERV	HV	HX S/G	HX	LG	MOV	PUMP	PZV	RV	SV	TK
Cavitation Erosion																	
Contamination Sedimentation Fouling																	
Corrosion Fatigue																	
Creep/Shrinkage																	
Crevice Corrosion																	
Denting									✓(1)								
Dynamic Loading																	
Electrical Stressors																	
Erosion													✓(3)				
Erosion Corrosion									✓(3)								
Fatigue	✓(4)	✓(4)			✓(4)	✓(4)	✓(4)		✓(4)			✓(4)	✓(4)	✓(4)	✓(4)		
Galvanic Corrosion								✓(5)					✓(5)				
General Corrosion	✓(5)	✓(5)			✓(5)		✓(5)		✓(5)			✓(5)	✓(5)	✓(5)	✓(5)		
Hydrogen Damage																	
IGA										✓(6)							
Intergranular Corrosion																	
Irradiation Embrittlement																	
Microbiologically-Influenced Corrosion																	
Neutron Embrittlement																	
Oxidation																	
Particulate Wear Erosion																	
Pitting									✓(5)								
Radiation Damage																	
Saline Water Attack																	
Selective Leaching																	
SCC	✓(7)	✓(7)			✓(7)	✓(7)	✓(7)	✓(7)	✓(7)			✓(7)		✓(7)	✓(7)		
IGSCC	✓(7)	✓(7)												✓(7)			
PWSCC									✓(7)					✓(7)			
Stress Relaxation																	
Thermal Damage																	
Thermal Embrittlement	✓(8)												✓(8)	✓(8)			
Wear	✓(2)	✓(2)		✓(2)		✓(2)	✓(2)	✓(2)	✓(2)	✓(2)		✓(2)	✓(2)	✓(2)			

✓ indicates plausible ARDM determination
(#) Indicates the group in which this ARDM is evaluated

Group 1 (denting) - Materials and Environment

Table 4.1-5 shows that denting is plausible for the SG HX tubes, which are fabricated from Alloy 600. [Reference 2, Attachments 5, 6, HX-01] Denting only occurs on the secondary side (on the SG HX tube exterior surfaces). The secondary side of these HX tubes are exposed to the internal environment of the SGs.

The internal SG secondary side environment during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapters 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

Group 1 (denting) - Aging Mechanism Effects

Denting refers to mechanical deformation of the SG tubes at support plates due to accelerated corrosion of the support plate structures. The corrosion products have a lower density than the base metal and tend to fill the space between the supports and the tubes. When the spaces are filled, additional corrosion causes the tubes to deform. Tube denting has been observed in CE SGs. [Reference 2, Attachments 7, HX - SG]

Therefore, denting was determined to be plausible for the SG HX tubes for which aging effects must be managed during the period of extended operation.

Group 1 (denting) - Methods to Manage Aging

Mitigation: Design features, such as the proper design and material selection of the RCS device types susceptible to this ARDM, can mitigate the effects of denting. Maintaining proper chemistry control on the secondary side of the SG could aid in mitigating the effects of denting.

Discovery: Denting of the SG HX tubes can be discovered by remote examination during plant refueling outages. Indications of denting identified during examinations of RCS components during refueling outages can be recorded and evaluated for potential damage.

Group 1 (denting) - Aging Management Program(s)

Mitigation: There are no programs to mitigate the effects of denting other than the proper design and material selection for the intended application. No credit is taken for secondary chemistry control in the mitigation of denting.

Discovery: The CCNPP Surveillance Test Procedures STP-M-574-1/2, "Eddy Current Examination of CCNPP 1/2 SGs," are credited for discovering denting in SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. The evaluation of SG HX tubes is accomplished with this procedure, Electric Power Research Institute (EPRI)/industry guidelines, and CCNPP Technical Specifications. The SG HX tubes are ranked in categories of degradation according to the CCNPP Technical Specifications. The Technical

Specifications have three categories for inspection results based on the percentage of tubes that are classified as degraded and defective. The eddy current acceptance criteria for SG HX tubes are:

- Imperfection - means an exception to the dimensions, finish, or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.
- Degraded tube - means a tube containing imperfections ≥ 20% of the nominal wall thickness caused by degradation.
- Defect - means an imperfection of such severity that it exceeds the plugging or repair limit. A tube containing a defect is defective. Any tube that does not permit the passage of the eddy-current inspection probe shall be deemed a defective tube.
- Plugging or repair limit - means the imperfection depth at or beyond which the tube shall be removed from service by plugging, or repaired by sleeving in the affected area because it may become unserviceable prior to the next inspection. The plugging or repair limit imperfection depths are specified as 40% of original nominal tube wall thickness or 40% of Westinghouse laser-welded sleeve wall thickness.

An Issue Report (IR) is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure before the next inspection. The inspection frequency for SG HX tubes is determined by the CCNPP Technical Specifications. [References 27 and 28] For purposes of SG tubing, "susceptible to failure" means active degradation has been identified through inspection and the tube is susceptible to not satisfying structural integrity limits prior to the next refueling outage (or next inspection).

The Unit 1 and 2 SG tubes are inspected during each unit's refueling outage. Inspections are based on EPRI guidance, applicable industry experience, Technical Specifications and site-specific SG degradation characteristics. Consistent with this, BGE is currently an active participant on committees sponsored by EPRI, CE Owners Group, and the Nuclear Energy Institute focusing on preservation of SG structural integrity.

Group 1 (denting) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the SG HX tubes that are susceptible to denting:

- The SG HX tubes are a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design conditions.
- Denting is plausible for the SG HX tubes and could result in the deformation of component material, leading to the loss of the pressure-retaining boundary function.
- The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering denting of the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.

Therefore, there is reasonable assurance that the effects of denting will be managed in order to maintain the pressure boundary integrity for the Group 1 components listed above under all design conditions required by the CLB during the period of extended operation.

Group 2 (wear) - Materials and Environment

Table 4.1-3 shows that wear is plausible for some of the RCS components. These susceptible RCS components and their material characteristics are: [Reference 2, Attachments 4, 5, 6, -CC-02/03/04, -GC-01/02/03/04/05/06, CV-01, ERV-01,-HC-01, HV-01/03/04, HX-01/02, PUMP-01, PZV-01, MOV-01/02]

- -CC - pipe flanges (stainless steel);
- -GC - pipe flanges (stainless steel);
- CV - bonnet/internals and bolting (stainless steel);
- ERV - body/internals (stainless steel);
- -HC - pipe flanges (stainless steel);
- HV - body and bonnet (forged or cast austenitic stainless steel [CASS]), stem (stainless steel);
- SG HX primary manway, manway cover (carbon steel), studs and nuts (alloy steel); secondary manway and manway cover plate (carbon steel), studs (alloy steel) and nuts (carbon steel), secondary handhole and handhole cover plate (carbon steel), studs (alloy steel) and nuts (carbon steel);
- SG HX tubes (Alloy 600);
- RCP seal water HX tubes (stainless steel);
- PUMP (RCP) case and pump cover (CASS), closure studs and nuts (carbon steel);
- Pressurizer manway forging and cover plate (carbon steel or alloy steel); and
- MOV - body/bonnets (austenitic stainless steel), for some MOVs with stainless steel discs and stems, and some MOV seats (stellite).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapters 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

Group 2 (wear) - Aging Mechanism Effects

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard abrasive particles (abrasive wear), or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). In addition to material loss from the above wear mechanisms, impeded relative motion between two surfaces held in intimate contact for extended periods may result in galling/self welding. Wear most typically occurs in components that experience considerable relative motion such as valves and pumps, in components that are held under high loads with no motion for long periods (i.e., valves, flanges), or in clamped joints where relative motion is not intended but occurs due to loss of clamping force (e.g., tubes in supports, valve stems in seats, springs against tubes). [Reference 2, Attachments 7, HX]

Wear can also occur between closures/closure cover plates and by flow induced vibrations causing a rubbing action between components. [Reference 2, Attachments 6, HX] Therefore, wear was determined to be plausible for the Group 2 components for which aging effects must be managed during the period of extended operation.

Group 2 (wear) - Methods to Manage Aging

Mitigation: Design features such as the proper design and material selection of the RCS device types susceptible to this ARDM can mitigate the effects of wear. Mechanical wear on those components that are manipulated during refueling operations can occur, but they usually are not subject to mechanical wear during normal operation. Minimizing the amount of component manipulation can mitigate wear.

Discovery: With proper design, mechanical wear occurs slowly over long periods of time and is revealed as material loss of the components themselves. This wear can be discovered and monitored by visual inspection of the affected areas. Visual inspections of components can find mechanical wear on the components.

Indications of wear identified during visual examinations of RCS components during refueling outages can be recorded and evaluated for potential damage. Evidence of this mechanical wear could then lead to corrective actions being taken to restore the design function of the affected components.

Group 2 (wear) - Aging Management Program(s)

Mitigation: There are no programs to mitigate the effects of wear other than the proper design and material selection for the intended application.

Discovery: The CCNPP Administrative Procedure MN-3-110, "ISI of ASME Section XI Components," is one of the existing programs designed to detect and manage the aging effects of wear for the RCS components susceptible to wear. [Reference 2, Attachments 8] The Inservice Inspection (ISI) Program

Plan responds to the requirements of Section XI of the ASME Code, 1983 Edition through Summer 1983 Addenda, and is subject to periodic update per 10 CFR 50.55a. [Reference 30, Section 1.2.1]

The scope of the existing ISI Program for the RCS includes examination and inspection of components identified in ASME Section XI (e.g., Subsection IWB, etc.). [Reference 31, Section 1.2A] The ISI Program is performed to meet the requirements of references identified in Section 1.2A of Reference 31. An extensive list of the developmental and performance references for the existing ISI program is provided in Section 2.0 of Reference 31.

Inservice inspection requirements in ASME Section XI, as implemented by the existing ISI Program, provide for visual examination of accessible surfaces of RCS components. [Reference 32, Table IWB-2500-1] The ASME Section XI ISI visual examination of the RCS components requires determining the general mechanical and structural conditions of the components from the effects of wear. Examinations may require, as applicable, determination of structural integrity, measurement of clearances, detection of physical displacements, structural adequacy of supporting elements, connections between load-carrying structural members, and tightness of bolting. [Reference 32, IWA-2213 Visual Examination VT-3]

If any abnormal condition is identified, the ASME Code provides requirements for the timely correction of the condition. [Reference 32, IWA-4130 Repair Program] Visual inspections can readily identify damage to the RCS components from wear. The corrective actions taken will ensure that the RCS components remain capable of performing their intended function under all CLB conditions.

The ISI Program is subject to internal and independent assessments and is recognized through these assessments as performing highly effective examinations and aggressively pursuing continuous improvements. Baltimore Gas and Electric Company monitors industry initiatives and trends in the area of ISI and non-destructive examination and plays a leadership role in developing, analyzing, and advancing non-destructive examination and ISI methods. The program is also subject to frequent external assessments by the Institute for Nuclear Power Operation, NRC, and others.

Operating experience relative to the ISI Program at CCNPP has been such that no site specific problems or events have required changes or adjustments. The program has been effective in its function of performing examinations required by ASME Section XI with respect to wear.

The CCNPP Boric Acid Corrosion Inspection (BACI) Program, MN-3-301, is credited with the discovery of wear of RCS components. The discovery of boric acid residue could indicate RCS leakage as the result of component wear. The ISI Program required the establishment of the Boric Acid Corrosion Monitoring Program to systematically ensure that boric acid corrosion does not degrade the primary system boundary. [Reference 31, page 23, Section 5.8.A.1.] The program controls examination and test methods and actions to minimize the loss of structural and pressure retaining integrity of RCS pressure boundary components due to boric acid corrosion. [Reference 31, Section 3.0.C] The basis for the establishment of the program is Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in pressurized water reactor (PWR) plants. [Reference 33, Section 1.1]

The scope of the program is threefold: (1) It provides examination locations where leakage may cause degradation of the primary pressure boundary by boric acid corrosion; (2) It provides examination requirements and methods for the detection of leaks; and (3) It provides the responsibilities for initiating engineering evaluations and the subsequent proposed corrective actions. [Reference 33, Section 1.2]

Under the BACI Program the VT-2 (a type of visual examination described in ASME XI, IWA-2212) walkdown examinations must be performed in accordance with ASME XI, IWA-2212, and the VT-1 examinations must be performed in accordance with ASME XI, IWA-2211. The VT-2 walkdown examinations must include the accessible external exposed surfaces of pressure-retaining, noninsulated components; floor areas or equipment surfaces located underneath noninsulated components; vertical surfaces of insulation at the lowest elevation where leakage may be detected and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas where water may be channeled for insulated components whose external insulation surfaces are inaccessible for direct examination; and for discoloration or residue on any surface for evidence of boric acid accumulation. Any leakage detected must be reported on an IR for corrosion degradation assessment. [Reference 33, Section 5.2]

Upon reaching reactor shutdown, ISI personnel are required to perform a containment walkdown visual inspection (VT-2) as soon as possible after attaining hot standby condition to identify and quantify any leakage found in specific areas of the Containment Building. A second ISI walkdown is performed prior to plant startup (at normal operating pressure and temperature) if leakage was identified and corrective actions taken. The ISI must ensure that all components that are subject of IRs where boric acid leakage has been found are examined in accordance with the requirements of this program. [Reference 33, Sections 5.1 and 5.2] Calvert Cliffs Administrative Procedure QL-2-100, "Issue Reporting and Assessment," defines requirements for initiating, reviewing, and processing IRs, and resolution of issues. The IRs are generated to document and resolve process and equipment deficiencies and nonconformances. [Reference 34, Sections 1.1 and 1.2]

Additionally, the program has evolved with regard to boric acid leaks discovered during other types of walkdowns and inspections. The program dictates a minimum qualification level of Level II Inspectors for the evaluation of boric acid leaks. Apparent leaks that are discovered during these other walkdowns/inspections are documented in IRs by the individual discovering the leak. These IRs are then routed to the ISI organization for closer inspection and evaluation by a Level II Inspector for disposition. This approach provides for more boric acid leakage inspection coverage and ensures boric acid leakage and its effects are properly evaluated.

Issue Reports that have been written in accordance with this program are required to address: (1) the removal of the boric acid residue; and (2) the inspection of the affected components for general corrosion. If general corrosion is found on a component, the IR is to provide an evaluation of the component for continued service and corrective actions to prevent recurrence. [Reference 33, Section 5.3]

Calvert Cliffs Technical Procedure RCS-10, "Pressurizer Manway Cover Removal and Installation," is also credited with the discovery of wear on the pressurizer components. The procedure contains steps that direct the user to inspect the studs (if they were not removed) for the presence of boric acid. The procedure also directs the user to contact the ISI organization to perform visual inspections of the pressurizer manway studs and nuts to ensure that they are acceptable for reuse. If boric acid is present, RCS-10 directs the cleaning and lubrication of the pressurizer manway studs and nuts. [Reference 35]

Technical Procedure RCS-10 is performed during refueling outages. This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs Technical Procedures SG-1, "Steam Generator Secondary Manway Cover Removal," and SG-2, "Steam Generator Secondary Manway Cover Installation," are both credited with discovery of wear on the SG manway closure surfaces. Procedures SG-1 and SG-2 both direct the user to inspect the seating surfaces for defects, and if defects are found, to notify the job supervisor. The procedures also require the studs to be inspected prior to installation of the manway covers. [References 36 and 37] Both SG-1 and SG-2 are performed during refueling outages. This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs Technical Procedures SG-5, "Steam Generator Secondary Handhole Cover Removal," and SG-6, "Steam Generator Secondary External Handhole Cover Installation," are both credited with discovery of wear on the SG secondary handhole closure surfaces. Procedures SG-5 and SG-6 both direct the user to inspect the seating surfaces for defects or smoothness, and if defects are found, to notify the job supervisor. [References 27 and 28] Both SG-1 and SG-2 are performed during refueling outages.

Calvert Cliffs Surveillance Test Procedures STP-M-574-1/2 are credited for discovering of wear on SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. Refer to Group 1 (denting) for a discussion of this surveillance program. [Reference 38 and 39]

Calvert Cliffs Surveillance Test Procedures STP-O-27-1/2, "Reactor Coolant System Leakage Evaluation," are credited for discovering wear on the RCS valve discs and seating surfaces. The procedure will discover wear on RCS valves by determining if any of them are leaking RCS coolant. Calvert Cliffs procedures STP-O-27-1/2 directs the user to perform calculations to determine the amount and potential source of RCS leakage. Any abnormal RCS leakage would be detected and actions taken to correct the leakage prior to a loss of the valve intended function. The basis for the acceptance criteria of leakage rates are provided by the CCNPP Technical Specifications. The CCNPP Surveillance Test Procedures STP-O-27-1/2 are performed in conjunction with CCNPP Technical Procedure CP-224, "Primary to Secondary Leak Rate." [Reference 40] This program has been observed to be historically effective in managing the applicable aging mechanism(s).

Calvert Cliffs Technical Procedure SG-20, "Steam Generator Primary Manway Cover Removal and Installation," is credited with the discovery of wear on the SG primary manway flange seating surfaces. The procedure directs the user to inspect the SG primary manway flange sealing surfaces for flaws and to clean the gasket surface areas. In addition, SG-20 requires the user to ensure that all studs and nuts have been inspected by BGE's Materials Engineering and Inspection Unit prior to installation. [Reference 41] This procedure is performed during plant refueling outages. This program has been observed to be historically effective in managing the applicable aging.

Calvert Cliffs will continually review industry activity and experience with respect to wear of tube in tube RCP seal water heat exchangers with CCNPP Administrative Procedure NS-1-100, "Use of Operating Experience and the Nuclear Hotline." Calvert Cliffs will take appropriate actions if any wear-induced pressure boundary leakage occurs in RCP seal water heat exchangers. [Reference 2, Attachments 8, 10]

Group 2 (wear) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the components listed under the Materials and Environment section that are susceptible to wear:

- The Group 2 components listed above provide the RCS pressure-retaining boundary and containment isolation function, so their integrity must be maintained under CLB design conditions.
- Wear is plausible for the Group 2 components mentioned above. Wear could result in the loss of component material and lead to the loss of the passive intended functions.
- The CCNPP Administrative Procedure MN-3-110 provides for the inspection of Group 2 components per the requirements of ASME Section XI. Though wear cannot be completely prevented, the status of pressure-retaining components can be evaluated on a basis that allows for corrective actions to be taken as conditions indicate component wear.
- The CCNPP BACI Program provides for examination of potential corrosion of the Group 2 components described above and subsequent cleanup of any boric acid residue present on them.
- The CCNPP Technical Procedure RCS-10 provides for the inspection of the pressurizer manway seating surfaces for wear and manway studs/nuts for the presence of boric acid.
- The CCNPP Technical Procedures SG-1 and SG-2 provide for the discovery of wear on the SG manway closure surfaces.
- The CCNPP Technical Procedures SG-5 and SG-6 provide for the discovery of wear on the SG handhole closure surfaces.
- The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering wear on the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- The CCNPP Surveillance Test Procedures STP-O-27-1/2 are credited for discovering wear on the RCS valve discs and seating surfaces that perform a pressure boundary function by performing RCS leak rate calculations. The RCS is subject to Technical Specifications for addressing any abnormal leakage.
- The CCNPP Technical Procedure SG-20 requires inspection for wear/flaws on the SG primary manway cover flange seating surfaces.
- Calvert Cliffs will continually review industry experience for RCP seal water HX tube wear in accordance with CCNPP Administrative Procedure NS-1-100. Calvert Cliffs will take appropriate action if the industry experiences degradation of these HXs resulting from tube wear.

Therefore, there is reasonable assurance that the effects of wear will be managed in order to maintain the pressure boundary integrity for the Group 2 components listed above under all design conditions required by the CLB during the period of extended operation.

Group 3 (erosion/erosion corrosion) - Materials and Environment

Table 4.1-3 shows that erosion is plausible for some RCP components and erosion corrosion is plausible for some SG HX components. These susceptible RCS components and their material characteristics are: [Reference 2, SG HX, PUMP-01, Attachments 4, 5, 6]

- SG HX - main steam outlet nozzles forging (alloy steel), secondary manway and manway cover plate (alloy steel), secondary handhole (carbon steel), and handhole cover plate (alloy steel); and
- RCP - case and pump cover (CASS).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately $134x10^6$ lbm/hr. [Reference 1, Section 4.1.1, Table 4-1] The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

Group 3 (erosion/erosion corrosion) - Aging Mechanism Effects

Erosion is caused by the high-velocity steam, water, or two-phase mixture (which may include particles) impinging on materials or leaking from joints. This mechanical wear or abrasion can be characterized by grooves, gullies, waves, holes, or valleys on a metal surface. Erosion corrosion is the acceleration of a corrosive process because of the erosion of the protective oxide film, which results in chemical attack or dissolution of the underlying metal. Erosion corrosion also occurs in environments with high velocity water (single or two-phase) having flow disturbances, low oxygen content, and fluid pH < 9.3. Erosion corrosion is also increased by component geometries that cause disturbances in the flow stream. [Reference 2, Attachments 7, Valve]

The specified SG HX components are subjected to environments that are conducive to erosion corrosion, while the specified RCP components are subjected to environments conducive to erosion. Therefore, erosion and erosion corrosion were determined to be plausible ARDMs for the Group 3 components for which aging effects must be managed. [Reference 1, Attachments 6s, HX, PUMP]

Group 3 (erosion/erosion corrosion) - Methods to Manage Aging

Mitigation: Design features, such as the proper material selection (and proper installation) of the RCS device types susceptible to these ARDMs, can mitigate the effects of erosion/erosion corrosion.

Discovery: Erosion and erosion corrosion can occur over time and are revealed as material loss of the components themselves. These effects can be discovered and monitored by visual inspection of the potentially affected areas. Visual inspections of these components could find any potential erosion/erosion corrosion on the components. Programs that monitor erosion corrosion could be utilized as a means of tracking and discovering the onset of these aging mechanisms before the RCS components fail to perform their intended function.

Programs/procedures that look for RCS leakage also augment the management of erosion/erosion corrosion by discovering leakage and performing subsequent corrective actions that would alleviate conditions leading to these ARDMs.

Group 3 (erosion/erosion corrosion) - Aging Management Program(s)

Mitigation: There are no CCNPP programs credited with the mitigation of erosion/erosion corrosion. The following discovery programs can limit the effects of these ARDMs by taking corrective actions when they are discovered.

Discovery: The CCNPP Administrative Procedure MN-3-110 is one of the existing programs designed to detect and manage the aging effects of erosion corrosion of the SG main steam outlet nozzles. [Reference 2, Attachments 8 TPR] The ISI Program refers to an ultrasonic procedure that examines the SG main steam outlet nozzle inner radius area. This procedure directs the user to refer to the ASME Boiler and Pressure Vessel Code Section XI, Table IWB-3512-1 for evaluation criteria of the ultrasonic examination results. [Reference 42] Refer to the previous discussion of the ISI Program under Group 2 (wear) under Aging Management Programs.

Calvert Cliffs BACI Program is credited with the discovery of erosion of the joint before the RCP case and pump cover. The procedure requires investigation of any boric acid leakage that is found on these components during walkdowns. Refer to the previous discussion of the BACI Program under Group 2 (wear) - Aging Management Programs.

Group 3 (erosion/erosion corrosion) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the Group 3 components:

- The Group 3 components provide a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design loading conditions.
- Erosion is plausible for RCP components listed above. This could result in the loss of component material and lead to the loss of the pressure-retaining boundary function.
- Erosion corrosion is plausible for the SG main steam outlet nozzles. This could result in the loss of component material and lead to the loss of the pressure-retaining boundary function.
- Calvert Cliffs' ISI Program is credited with the discovery of erosion corrosion on the SG main outlet nozzles using ultrasonic examinations. The program requires the performance of corrective actions before a pipe/nozzle wall thins to below the minimum required wall thickness necessary for the pipe/nozzle to perform its intended function.
- Calvert Cliffs BACI Program is credited with the discovery of erosion on the joint before the RCS case and pump cover. This program also provides for examination of potential corrosion of the

RCS device types described above and subsequent cleanup of any boric acid residue present on them.

Therefore, there is reasonable assurance that the effects of erosion and erosion corrosion will be managed in order to maintain the pressure boundary integrity for the RCS device types listed above under all design conditions required by the CLB during the period of extended operation

Group 4 (fatigue) - Materials and Environment

Table 4.1-3 shows that fatigue is plausible for some of the RCS device types. These susceptible RCS device types and their material characteristics are: [Reference 2, -CC-01/02/03/04/05/06, -GC-01/02/03/04/05/06, CKV-01, CV-01, ERV-01, HX-01, MOV-01/02, PUMP-01, PZV-01, RV-01 Attachments 4, 5, 6]

- -CC - includes all piping subcomponents such as nozzles, forgings, welds, safe ends, and thermal sleeves (piping is stainless steel, safe ends are CASS);
- -GC - pipe (stainless steel), flanges (stainless steel), bolting studs (alloy steel), bolting hex nuts (carbon steel), welds (stainless steel);
- CKV - body/bonnet (stainless or carbon steel) and bolting (carbon steel);
- CV - body/bonnet (CASS) and bonnet/internals (stainless steel);
- ERV - cage (CASS) and body/internals (stainless steel);
- SG HX - lower shell segments, upper shell segment, upper cone segment, top head peel segments (carbon steel), top head dome segment, steam outlet nozzle forging, steam outlet safe end, feedwater nozzle forging, feedwater nozzle safe end (alloy steel), and secondary welds (alloy steel);
- MOV - body/bonnet (austenitic stainless steel, stainless steel), disc and stem (CASS and stainless steel), and seat (stellite on CASS);
- PUMP - (RCP) case and pump cover (CASS), closure studs and nuts (carbon steel);
- PZV - all pressurizer subcomponents are susceptible to fatigue (main shell, head and bottom plates are alloy steel with stainless steel or Alloy 600 cladding); and
- RV - base (austenitic stainless steel), nozzle (alloy steel), disc (CASS).

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained. The RCS components listed are subject to thermal and mechanical cyclic loading during RCS heat-up and cool-down and other plant operational events.

Group 4 (fatigue) - Aging Mechanism Effects

Low-cycle fatigue is a mechanism that initiates and propagates flaws under the influence of fluctuating or cyclic applied stress. Fatigue is influenced by variables that include: mean stress, stress range, environmental conditions, surface roughness, and temperature. Thermal stresses develop when a material is heated or cooled. Generally, fatigue failures occur at stresses having a maximum value less than the yield strength of the material. If a component is repeatedly subjected to loads of sufficient magnitude, a fatigue crack or cracks will eventually be formed in some highly stressed region and may gradually progress through the metal until complete fracture occurs. [Reference 43, page 4-7] The cracks may then propagate under continuing cyclic stresses.

The fatigue life of a component is a function of several variables such as stress level, stress state, cyclic wave form, fatigue environment, and the metallurgical condition of the material. Failure occurs when the endurance limit number of cycles (for a given load amplitude) is exceeded. [Reference 2, Attachments 7s]

The RCS device types listed above are subject to a wide variety of varying mechanical and thermal loads. [Reference 2, Attachments 7s] Plant transients apply cyclical thermal loading and pressurization that contribute to fatigue accumulation on the RCS device types above. The limiting locations for low-cycle fatigue in the RCS and their controlling transients are: [Reference 44, Table 5-1]

- Pressurizer Spray System - cycle of the pressurizer spray;
- Safety injection nozzle - plant cooldown (initiation of shutdown cooling);
- Charging inlet nozzle - loss of charging flow and recovery, loss of letdown flow and recovery, regenerative heat exchanger isolation;
- Pressurizer surge nozzle - pressurizer heatup and plant cooldown;
- SG secondary shell - initiation of main feedwater, initiation of auxiliary feedwater;
- SG feedwater nozzle - initiation of main feedwater;
- Pressurizer bottom head and support skirt - plant cooldown, reactor trip;
- Shutdown cooling outlet nozzle - plant cooldown; and
- SG tube-to-tubesheet weld - primary leak test RCS heatup.

American Society of Mechanical Engineers Section III requires the design analysis for Class 1 components to address fatigue and establishes limits such that initiation of fatigue cracks is precluded. Section III defines the fatigue threshold in terms of a cumulative fatigue usage factor (CUF). The low-cycle fatigue "damage" from a particular transient depends on the magnitude of the stresses applied. The summation of fatigue usage over all transients of all types is the CUF. Crack initiation is conservatively assumed to have occurred at a CUF equal to one.

The CUF can be determined from the actual or predicted transient history for the component and limits established on the number of transients.

Group 4 (fatigue) - Methods to Manage Aging

Mitigation: The effects of low-cycle fatigue can be mitigated by operational practices that reduce the number and severity of thermal transients on the RCS components and by proper design and material selection. Therefore, the effects of fatigue can be mitigated by operational practices that reduce the number and severity of pressure and thermal transients, by fuel management practices that minimize the number of refuelings, and by proper design and material selection.

Discovery: Fatigue cracks can be discovered by inspecting components, and the scope and frequency of inspections can be established based on the likelihood that fatigue cracks have initiated. As discussed above, low-cycle fatigue is accounted for in the original design in accordance with ASME Code Section III. Monitoring the number of design-basis transients and/or the accumulated fatigue usage can be used to predict the end of fatigue life.

American Society of Mechanical Engineers Code Section III also provides accepted practices for analyzing Class I components for thermal fatigue combined with all other loads that must be considered under the CLB. An inspection program designed to identify crack initiation can be effective in discovering the effects of this aging mechanism prior to loss of the RCS pressure boundary function. The RCS components listed above can be inspected during plant refueling outages.

Group 4 (fatigue) - Aging Management Program(s)

Mitigation: As part of general operating practice, plant operators minimize the duration and severity of transitory operational cycles. Further modification of plant operating practices to reduce the magnitude and/or frequency of thermal transients would place additional unnecessary restrictions on plant operations. This is because the detection and monitoring activities discussed below are deemed adequate for effectively managing fatigue in the RCS. No credit has been given to the 24-month fuel cycle since plant transients other than refueling could cause plant heat-ups and cool-downs.

Discovery: The CCNPP Fatigue Monitoring Program (FMP) records and tracks the number of critical thermal and pressure test transients. Cycle counting is performed as part of this program. The data for thermal transients is collected, recorded, and analyzed using a safety-related software package. The software is used to analyze data that represents real transients and to predict the number of transients for 40 and 60 years of plant operation based on the historical records. This information is used to verify that the RCS critical locations will not experience more than the allowable number of cycles for those locations. [Reference 44, Tables 4-1, 4-7, Reference 45] The Improved Standard Technical Specifications for CCNPP, which will be implemented in 1997, will contain a requirement for tracking cyclic and transient occurrences to ensure that components are maintained within the design limits.

The current FMP monitors and tracks low-cycle fatigue usage for the limiting components of the NSSS and the SG safe-ends-to-reducer welds. Eleven locations in these systems have been selected for monitoring for low-cycle fatigue usage; they represent the most bounding locations for critical thermal and pressure transients and operating cycles. [References 44 and 45] The RCS critical (or bounding) locations and their controlling transients for fatigue are listed above in the Aging Management Effects section. [Reference 44, Sections 4.1, 4.8] A one-time fatigue analysis will be performed for the RCPs, MOVs, and pressurizer RVs to determine if these components are bounded by components and transients currently included in the FMP. If these components are not bounded they will be added to the FMP. [Reference 2, Attachments 10]

The original design fatigue analysis of the RCS components (which was incorporated into the FMP) determined the critical locations and corresponding transients. All transients that contribute to low-cycle fatigue usage are accounted for as part of the original design fatigue analysis. The FMP only tracks certain critical transients (see list of transients and components under Methods to Manage Aging). The contribution to fatigue usage for all other design transients is accounted for by an "initial" fatigue usage. The software package adds subsequent fatigue usage resulting from RCS pressure and temperature transients to "initial" fatigue usage to obtain the current CUF. [Reference 44 Sections 4.1, 4.8, Reference 46]

The current FMP tracks low-cycle fatigue usage using both cycle counting and stressed-based analysis. In accordance with ASME Code Section III, the fatigue life of a component is based on a calculated CUF of less than or equal to one. The CUF and actual number of transients for limiting locations in the NSSS and SGs are determined using plant thermal and pressure data. The CUF for several locations, including the pressurizer surge line, is also calculated using stress-based analysis techniques. [References 45, 46, and 47]

Plant parameter data is collected on a periodic basis and reviewed to ensure that the data represents actual transients. Valid data are entered into the software, which counts the critical transient cycles and calculates the CUFs. Based on ASME Code Section III, a CUF less than or equal to one, and/or the number of cycles remaining below the design allowable number, are acceptable conditions for any given component since no crack initiation would be predicted.

The number of cycles and CUF are calculated on a semi-annual basis, which provides a readily predictable approach to the alert value. [Reference 47, Section 1.1] In order to stay within the design basis, corrective action is initiated well in advance of the CUF approaching one or the number of cycles approaching the design allowable, so that appropriate corrective actions can be taken in a timely and coordinated manner. [Reference 47]

Modifications have been made to the FMP recognizing lessons learned. For example, analysis techniques, such as stress-based analysis, have been implemented for locations that have unique thermal transients or involve unique geometry. Other modifications have been made to reflect changes or proposed changes to plant operating practices, and to reflect plant operating conditions more accurately. The plant design change process requires the FMP to consider any proposed changes that affect the fatigue design basis or transient definitions. [References 45 and 48]

The CCNPP FMP has been inspected by the NRC, which noted that this monitoring system can be used to identify components where low-cycle fatigue usage may challenge the remaining and extended life of the components and can provide a basis for corrective action where necessary. The program is controlled in accordance with EN-1-300, "Implementation of Fatigue Monitoring." [Reference 49] Since the FMP has been initiated, no locations have reached their design allowable number of cycles or a CUF of greater than or equal to one. The CUFs through 1996 for the RCS components listed above are: [Reference 45]

	Unit 1	Unit 2
• Pressurizer Spray System	0.33877	0.32699
• Safety Injection Nozzle	0.00992	0.00925
• Charging Inlet Nozzle 1	0.11515	0.11615
• Charging Inlet Nozzle 2	0.11515	0.11616
• Pressurizer Surge Nozzle	0.13137	0.09635
• SG Secondary Shell 1	0.08957	0.09110
• SG Secondary Shell 2	0.08951	0.09133
• Pressurizer Bottom Head and Support Skirt	0.26150	0.23734
• Shutdown Cooling Outlet Nozzle	0.15917	0.12896
• SG Tube-to-Tubesheet Weld 1	0.02653	0.02653
• SG Tube-to-Tubesheet Weld 2	0.02653	0.02653

To further address fatigue for license renewal, CCNPP participated in an EPRI-sponsored task to demonstrate the industry fatigue position. The task applied industry-developed methodologies to identify fatigue-sensitive component locations that may require further evaluation or inspection for license renewal and evaluate environmental effects as necessary. The program objective included the development and justification of aging management practices for fatigue at various component locations for the renewal period. The demonstration systems were the Feedwater System, the pressurizer surge line, and the Charging/Letdown System. [Reference 4, Page 3]

Generic Safety Issue 166

Generic Safety Issue 166, Adequacy of Fatigue Life of Metal Components, presents concerns identified by the NRC that must be evaluated as part of the license renewal process. The NRC staff concerns about fatigue for license renewal fall into five categories: The first is adequacy of the fatigue design basis when environmental effects are considered. This concern does not apply to the RCS because of stringent RCS water chemistry controls, exceptionally low oxygen concentrations (less than 5 parts per billion), and because the RCS carbon steel interior surfaces are clad with stainless steel. The second category concerns the adequacy of both the number and severity of design basis transients. Since these have already been analyzed for the CCNPP RCS, this concern does not apply. A third category, adequacy of ISI requirements and procedures to detect fatigue indications, does not apply because CCNPP does not rely on ISI as the sole means for detection of fatigue. Category four, adequacy of the fatigue design basis for Class 1 piping components designed in accordance with American Nuclear Standards Institute B31.1, does not apply because the RCS does not have piping components designed in accordance with B31.1. The fifth and last category, adequacy of actions to be taken when the fatigue design basis is potentially compromised, are adequately addressed by the CCNPP FMP. [Reference 50, 110

Group 4 (fatigue) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to the RCS components subject to low-cycle fatigue:

- The Group 4 components provide a pressure-retaining boundary for the RCS, so their integrity must be maintained under CLB design conditions.
- Low cycle fatigue is plausible for the Group 4 device types listed above.
- If left unmanaged, low-cycle fatigue could result in crack initiation and growth, which could impair the pressure-retaining function.
- The Group 4 device types are the bounding fatigue sensitive components for the RCS and are expected to bound the other RCS components for the effects of fatigue.
- The CCNPP FMP tracks all applicable plant transients and monitors the cycles and fatigue usage for the bounding RCS components.
- The FMP is controlled so that effective and timely corrective actions can be taken prior to a loss of RCS pressure boundary integrity resulting from fatigue damage.
- A one-time fatigue analysis will be performed for the RCPs, MOVs and pressurizer RVs to determine if these components are bounded by components and transients currently included in the FMP. If these components are not bounded they will be added to the FMP.
- Tracking the cycle and fatigue usage for the bounding RCS components will ensure that they and all other RCS components will not exceed their fatigue design basis.

Therefore, there is reasonable assurance that the effects of fatigue in RCS components will be managed in order to maintain the components' intended function under all design loading requirements of the CLB during the period of extended operation.

Group 5 (galvanic/general corrosion and pitting) -Materials and Environment

Table 4.1-3 shows that galvanic, general corrosion, and pitting are plausible for some of the RCS components. The RCS subcomponents listed below are susceptible to one or more of these ARDMs. These susceptible RCS components and their material characteristics are: [Reference 2, -CC-01/02/03/04, -GC-01/02/03/04/05/06, CKV-01, ERV-01, HV-04, HX-01, MOV-02, PUMP-01, PZV-01, RV-01, Attachments 4, 5, 6]

General Corrosion - External

- -CC - pipe, elbows, and nozzle forging (carbon steel), bolting studs (alloy steel), bolting hex nuts (carbon steel);
- -GC - bolting studs and bolting hex nuts (carbon steel);
- CKV - some of the CKVs bolting (carbon steel);
- ERV - bracket stud (alloy steel) and nut (carbon steel);

- SG HX - primary manway (alloy steel, clad - Alloy 600), manway cover plate (carbon or alloy steel), primary head torus (carbon steel with stainless steel clad), spherical head (carbon steel); secondary manway studs (alloy steel) and hex nuts (carbon steel), secondary manway yoke (carbon steel), handhole studs and nuts (alloy steel); primary manway studs and nuts (alloy steel); lower support sliding base and cap plate (carbon steel), lower support flange bolts (alloy steel), and flange nuts (carbon steel);
- MOV - bonnet stud and nut (carbon steel);
- PUMP - closure studs and nuts (carbon steel);
- Pressurizer - alloy steel shell, top head and bottom head (alloy steel); safety/relief valves, spray and surge nozzle forgings (forged alloy steel); manway forging (alloy steel), manway cover plate (carbon steel), manway bolting studs and bolts (alloy steel); carbon steel welds; support ring assembly and base ring assembly (carbon steel), support skirt forging (alloy steel), and lifting lugs (carbon steel); and
- RV - bonnet/spring/bonnet studs (carbon or alloy steel).

General Corrosion - Internal

- SG HX tube support structures (carbon steel components of various Grades and Classes)

Galvanic Corrosion - External

- HV - stem, disk and seat (stainless steel).

Pitting - Internal

- SG HX - tubes (Alloy 600) exposed to the SG internal (secondary side) environment.

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates, and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

For RCS carbon steel components clad on the interior surfaces with stainless steel, only exterior surfaces could be susceptible to the ARDMs in this group. The RCS contains boric acid that could leak onto the exterior of these carbon steel components. [Reference 2, Attachments 6s and 7s]

Group 5 (galvanic/general corrosion and pitting) - Aging Mechanism Effects

General corrosion is degradation that results in wall thinning (wastage) due to chemical attack (dissolution) by an aggressive environment to materials susceptible to that environment. An important concern is the leakage of boric acid on carbon steel components. Boric acid attacks and damages the components clad internally with stainless steel from the their exterior (carbon steel) surfaces. The consequences of the damage are a loss of load carrying cross-sectional area. General corrosion could lead to excessive wall thinning and failure of the RCS pressure boundary function for the RCS components. [Reference 2, Attachments 7s]

Galvanic corrosion is accelerated corrosion caused by dissimilar metals in contact in a corrosive or conductive solution. Galvanic corrosion requires two dissimilar metals in physical or electrical contact, developed electrical potential (material dependent), conducting solution, and a corrosive environment (i.e., oxygen or chlorides for example). [Reference 2, Attachments 7s]

Pitting is a form of localized general corrosion that results in holes in a metal. Pitting can lead to penetrations of the pressure boundary with a small amount of metal loss. Carbon steels, stainless steels, and Alloy 600 are susceptible to pitting in various degrees. Severe pitting of CE SG tubes has occurred at other power plants. [Reference 2, HX01, Attachments 7]

If left unmitigated in the long-term, galvanic/general corrosion could eventually result in failure of the Group 5 components pressure-retaining capability under CLB design loading conditions.

Group 5 (galvanic/general corrosion and pitting) - Methods to Manage Aging

Mitigation: The effects of these ARDMs cannot be completely prevented, but they can be mitigated by minimizing the exposure of the carbon steel surfaces of the RCS metal components to an aggressive chemical environment. Stainless steel cladding on the interior of some RCS components helps to reduce the effects of galvanic/general corrosion on the interior surfaces exposed to reactor coolant. However, mitigation of corrosion on the exterior surfaces of the Group 5 components requires minimization of RCS leakage from the RCS pressure boundary, and the removal of any boric acid residue from exterior RCS surfaces.

Discovery: The effects of galvanic/general corrosion on the RCS components can be discovered through a program of visual inspections on the RCS areas susceptible to these ARDMs. Inspection of the areas around the RCS components would identify leakage occurring and result in corrective actions being taken before corrosion could degrade the RCS intended function. Those Group 5 components that are not accessible to visual inspection (i.e., SG HX tubes - pitting) can be examined using remote sensing techniques.

Group 5 (galvanic/general corrosion and pitting) - Aging Management Program(s)

Mitigation:

External: The CCNPP BACI Program will mitigate the effects of boric acid corrosion on external carbon steel surfaces through discovery of minor leakage of RCS components and removal of any boric acid residue that is found during walkdown inspections. Removal of any boric acid leakage from component surfaces mitigates the effects of this substance on these surfaces. This program was previously described in Group 2 (wear) under Aging Management Programs.

Discovery:

External: Discovery of galvanic/general corrosion for RCS components is performed by the CCNPP BACI Program and Technical Procedure SG-20. These programs and procedures require the visual inspection of RCS components for boric acid leakage and corrosion. The CCNPP BACI Program is credited with discovery of galvanic/general corrosion for those RCS components listed as susceptible to these ARDMs. This program requires investigation of any boric acid leakage that is discovered. The BACI Program was previously discussed in Group 2 (wear) under Aging Management Programs. [Reference 2, Attachments 8]

The CCNPP MN-3-110, ISI of ASME Section XI Components, is credited with discovering galvanic/general corrosion on the RCP components and discovering general corrosion on RCS piping (pipe code -CC). Visual examination (VT-2) of external surfaces are performed for these RCS components in accordance with ASME Section XI IWA-2212. [Reference 2, Attachments 8]

The CCNPP Technical Procedure SG-20 is credited with the discovery of general corrosion on the SG primary manway bolting materials. The procedure directs the user to inspect the SG primary manway flange sealing surfaces for flaws and to clean the gasket surface areas. In addition, SG-20 requires the user to ensure that all studs and nuts have been inspected prior to installation. [Reference 41] This procedure is performed during plant refueling outages.

Internal: The CCNPP Technical Procedures STP-M-574-1/2 are credited for discovering pitting on SG HX tubes. The procedure implements the inspection requirements of the CCNPP Technical Specifications and defines the sample size for tube inspection, inspection process, evaluation, and determination of tube status. This procedure was previously described in Group 2 (wear) under Aging Management Programs. [References 38 and 39]

For internal corrosion of SG HX tube support structures, BGE is aware of SG flow-assisted corrosion at the San Onofre Nuclear Generating Station and will monitor industry activity related to this aging mechanism. Calvert Cliffs will respond to any NRC generic communications on this matter as part of the CLB. An evaluation of flow-assisted corrosion for CCNPP SGs will be incorporated into annual updates of the BGE LRA.

The corrective actions taken as a result these programs will ensure that the RCS components remain capable of performing their intended function under all CLB conditions during the period of extended operation.

Group 5 (galvanic/general corrosion and pitting) - Demonstration of Aging Management

Based on the material presented above, the following conclusions can be reached with respect to the galvanic/general corrosion and pitting of the Group 5 components:

- The Group 5 components provide a pressure-retaining boundary, and their integrity must be maintained under CLB design loading conditions.
- General corrosion is plausible for the Group 5 components listed as susceptible, which could lead to loss of pressure-retaining boundary integrity.
- Galvanic corrosion is plausible for the Group 5 hand valves, which could lead to loss of pressure-retaining boundary integrity.
- Pitting is plausible for the SG HX tubes, which could lead to loss of pressure-retaining boundary integrity.
- The CCNPP BACI Program provides for examination of potential galvanic and general corrosion of the RCS external surfaces and subsequent clean up of any boric acid residue.
- The CCNPP ISI Program provides for the inspection of RCS pipe and RCPs, per the requirements of ASME Section XI, for galvanic/general corrosion. Though galvanic/general corrosion cannot be completely prevented, the status of these components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate general corrosion.
- Calvert Cliffs Technical Procedure SG-20 will provide for the discovery of general corrosion or flaws on the SG primary manway cover flange seating surfaces and primary manway studs/nuts.
- Calvert Cliffs Technical Procedures STP-M-574-1/2 are credited for discovering pitting of the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- Examinations will be performed and appropriate corrective actions will be taken if galvanic/general corrosion or pitting are discovered.

Therefore, there is reasonable assurance that the effects of galvanic/general corrosion and pitting on RCS components will be managed in order to maintain the components pressure boundary integrity under all design conditions required by the CLB during the period of extended operation.

Group 6 (IGA) - Materials and Environment

Table 4.1-3 shows that IGA is plausible for the RCP seal water HXs, which are subjected to both the RCS and CC System environment. The RCP seal water HXs are fabricated from stainless steel. [Reference 2, HX-02, Attachments 4, 5, 6]

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately $134x10^6$ lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control. The internal environment of the CC System is chemically-treated water at a design pressure of 150 psig and a maximum design temperature of 180°F. [Reference 1, Section 9.5.2.1, Table 9-17]

Group 6 (IGA) - Aging Management Effects

Intergranular attack is similar to IGSCC, except that stress is not required for IGA. Intergranular attack is localized corrosion at or adjacent to grain boundaries, with relatively little corrosion of the material grains. It is caused by impurities in the grain boundaries, or the enrichment or depletion of alloying elements at grain boundaries, such as the depletion of chromium at austenitic stainless steel grain boundaries. Nickel alloys, such as Alloy 600, experience IGA in the presence of certain sulfur environments at high temperatures or when austenitic stainless steel weld filler material is inadvertently used on Ni-Cr-Fe alloys. The susceptibility of IGA can often be corrected by redistributing alloying elements more uniformly through solution heat treatment, by modifying the alloy to increase resistance to segregation, or by using a completely different alloy. [Reference 2, HX-02, Attachments 7s]

Group 6 (IGA) - Methods for Managing Aging

Mitigation: The effects of IGA can be mitigated on RCP seal water HXs by minimizing the exposure of the internal surfaces of the components to an aggressive environment. Maintaining system chemistry conditions to minimize impurities can limit the rate and effects of degradation due to these ARDMs.

Discovery: There are no feasible methods to discover IGA on the RCP seal water HXs other than indications of RCS leakage into the CC System. This RCS leakage is detected by radiation monitors in the CC System.

Group 6 (IGA) - Aging Management Program(s)

Mitigation: The effects of IGA will be mitigated for the RCP seal water HX by CCNPP Chemistry Procedure CP-204, "Specification and Surveillance Primary Systems," and CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems." Maintaining an RCS and CC System chemistry with minimal impurities will aid in the preventing IGA. [Reference 2, Attachments 1]

CP-204

Calvert Cliffs Technical Procedure CP-204 is credited with mitigating the effects of IGA on the RCP seal water HX (RCS side) by monitoring and maintaining the RCS chemistry. The chemistry controls provided by CP-204 have been established to: minimize impurity ingress to plant systems; reduce corrosion product generation, transport, and deposition; reduce collective radiation exposure through chemistry; improve integrity and availability of plant systems; and extend component and plant life. Maintaining system chemistry conditions to minimize impurities limits the rate and effects of component degradation. CP-204 is based on the Technical Specifications, BGE's interpretation of industry standards, and recommendations made by CE. [Reference 51, Sections 1.0, 2.0; Reference 52, Section 6.1.A]

The scope of CP-204 includes the following systems/components: [Reference 11, Section 2.0]

- Reactor Coolant (Modes 1 through 6);

- Spent Fuel Pool (Modes 1 through 6);
- Refueling Water Storage Tank (Modes 1 through 6);
- Refueling Pool (Mode 6);
- Safety Injection Tanks (Modes 1 through 6);
- High Pressure Safety Injection Pump Discharge (Modes 1 through 6);
- Boric Acid Storage Tank (Modes 1 through 6);
- Reactor Coolant Waste Receiver Tank (Modes 1 through 6);
- Reactor Coolant Waste Evaporator Bottoms (Modes 1 through 6);
- Boric Acid Batching Tank (Modes 1 through 6);
- Chemical and Volume Control Ion Exchangers (Modes 1 through 6); and
- Spent Fuel Pool Ion Exchangers.

Calvert Cliffs Technical Procedure CP-204 lists the parameters to monitor (e.g., chloride, fluoride, sulfate, oxygen, pH), the frequency of monitoring these parameters, and the acceptable value or range of values for each parameter. The primary chemistry parameters are measured at procedurally-specified frequencies (e.g., daily, weekly, monthly) and are compared against "target values," which represent a goal or predetermined warning limit. If a target value is approached or violated, corrective actions are taken as prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 50, Sections 3.0.C.4, 6.0]

The chemistry program at CCNPP (which includes CP-204) is subject to internal assessment activity both within the Chemistry Department and through the site performance assessment group. The program is also subject to external assessments by Institute for Nuclear Power Operations, NRC, and others. Operating experience relative to the chemistry program at CCNPP has shown it has been effective in its function of minimizing corrosion and corrosion-related failures and problems.

Calvert Cliffs Technical Procedure CP-204 provides for a prompt review of primary system chemistry parameters so that steps can be taken to return chemistry parameters to acceptable levels (within Technical Specification limits), and thus minimizing impurities and limiting the rate and effects of degradation due to corrosion mechanisms. [Reference 2, Attachments 8; Reference 50, Section 2.0]

CP-206

Calvert Cliffs Technical Procedure CP-206 is credited with mitigating IGA on the RCP seal water HX (CC System side) by monitoring and maintaining CC chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water that aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 53, Attachments 8]

Calvert Cliffs Technical Procedure CP-206 describes the surveillance and specifications for monitoring the CC System fluid. The procedure lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the CC System fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not a radioactive system). [Reference 54, Attachments 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. For pH, the current action level is less than 9.0 or greater than 9.8; for hydrazine the current action level is less than 5 or greater than 25 parts per million (ppm). Refer to Attachments 1 in CP-206 for the specific monitoring frequency and target values for each chemistry parameter. [Reference 54, Attachments 1]

Operational experience related to CP-206 has shown no problems related to use of this procedure with respect to the CC System. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added as a parameter to CP-206 to discover any unusual corrosion of the CC carbon steel components.

An internal BGE chemistry summary report for 1996 described the CCNPP Units 1 and 2 CC/Service Water Systems' chemistry as excellent. Action levels for all four systems were only exceeded on eight occasions, or approximately 0.7% of the time during the year. Over 70% of the action levels exceeded were due to major system changes during the 1996 refueling outage. Recommendations to correct this condition have been made to determine outage evolutions that can affect the CC/Service Water System chemistry and take action to prevent chemistry targets being exceeded.

The CC System usually operates within normal parameters, except when the system is restarted after an outage lay-up. During an outage lay-up, the affected CC components may experience some minor corrosion when the internal component surfaces are exposed to air. After the CC System is returned to service and flow is once again established, some of this minor corrosion is removed from the pipe inner surface and released into the system where it is detected. An increase in suspended solids (due to this effect) was seen on Unit 1 at the start of the 1996 outage, and was correlated to flow initiation through the shutdown cooling HXs. The level of suspended solids slowly decreased over the course of the year back to levels obtained before the outage. The Unit 2 suspended solids showed a fairly steady baseline with a few minor spikes occurring during the year.

Procedure CP-206 provides for a prompt review of CC chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and thus minimizes the effects of crevice corrosion/pitting.

Discovery: Procedure CP-206 is credited with the discovery of wear in the RCP seal water HX. If the HXs were to corrode through, radiation monitors on the CC System would detect this leakage from the RCS. Refer to the discussion above for details on CP-206.

Group 6 (IGA) - Demonstration of Aging Management

Based on the material presented above, the following conclusions can be reached with respect to the IGA of the Group 6 components:

- The RCP seal water HXs provide a pressure-retaining boundary, and their integrity must be maintained under CLB design loading conditions.
- Intergranular attack is plausible for the RCP seal water HXs, which could lead to loss of pressure-retaining boundary integrity.
- Calvert Cliffs Technical Procedure CP-204 will mitigate the effects of IGA on the RCP seal water HX (RCS side)by maintaining primary system chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensures prompt corrective actions will be taken when adverse chemistry parameters are detected.
- Calvert Cliffs Technical Procedure CP-206 will mitigate the effects of IGA on the RCP seal water HX (CC System side) by controlling the range of specific chemical parameters, and provide action levels that ensure timely correction of adverse chemistry parameters. The procedure will also provide for the discovery of RCS leakage into the CC System by monitoring for elevated radiation levels in the CC System.
- Examinations will be performed and appropriate corrective actions will be taken if IGA is discovered.

Therefore, there is reasonable assurance that the effects of IGA on the RCP seal water HXs will be managed in order to maintain the components pressure boundary integrity under all design conditions required by the CLB during the period of extended operation.

Group 7 (SCC/IGSCC/PWSCC) - Materials and Environment

Table 4.1-3 shows that SCC, IGSCC, and PWSCC are plausible for some of the RCS device types. It should be noted that the ARDMs IGSCC and PWSCC are variations of SCC that can affect different material types, that can occur in different environments, and that can be managed by similar and/or different aging management programs. The RCS components listed below are susceptible to one or more of these ARDMs. These susceptible RCS device types, applicable ARDM(s), and their material characteristics are: [Reference 2, -CC-01/02/03/04/06, -GC-01/02/03/04/05/06, CKV-01, CV-01, ERV-01, HV-04, HX-01, MOV-01/02, PZV-01, RV-01, Attachments 4, 5, 6, Table 4.2]

SCC/IGSCC/PWSCC

- PZV - pressurizer - pressure, level, and temperature nozzle forgings (except Unit 2 upper pressure and level forgings - Alloy 600), pressure, level, temperature, safety/relief valve and spray nozzle safe ends (stainless steel), surge nozzle safe end (stainless steel - cast), spray and surge nozzle thermal sleeve (Alloy 600), Unit 1 heater sleeve (Nickel-plated Alloy 600), manway bolting (alloy steel), welds (Alloy 600); and
- -CC - charging nozzle thermal sleeve, resistance temperature detector nozzle, pressure/sample nozzle neck, safety injection thermal sleeve, surge nozzle thermal sleeve (all are Alloy 600).

- SG HX - instrument nozzles (Alloy 600), HX tubes (Alloy 600) exposed to the internal (primary side) environment of the RCS and secondary side of the SGs, primary manway studs (alloy steel).

SCC/IGSCC

- -CC - bolting studs and hex nuts (carbon steel); RPV head closure seal leakage detection piping (stainless steel), fittings (stainless steel), and welds (stainless steel); and
- -GC -bolting studs (alloy steel) and hex nuts (carbon steel).

SCC

- CKV - bolting (carbon steel);
- CV - bolting (carbon steel);
- ERV - bracket studs (alloy steel) and nuts (carbon steel);
- HV - some bodies and bonnets (CASS or forged austenitic stainless steel);
- MOV - bonnet studs and nuts (carbon steel); and
- RV - bonnet/spring/bonnet studs (carbon or alloy steel).

Alloy 600 RCS components exposed only to the RCS primary water (i.e., not SG tubes) are only susceptible to PWSCC.

The internal RCS environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately 134×10^6 lbm/hr. [Reference 1, Section 4.1.1, Table 4-1]. The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control.

The internal SG environment (secondary side) during power generation is saturated steam and water at a design pressure/temperature of 1000 psig/580°F and normal operating parameters of approximately 850 psig/520°F. The SGs also contain chemically-treated, demineralized, high pressure water with high flow rates and fluid velocities at full power conditions. [Reference 1, Chapter 10.1, 10.2, Reference 26] During plant shutdown conditions, the SGs may be drained.

As the interface between the primary and secondary fluids, the SG HX tubes are subjected to both the internal RCS environment and the internal SG environment.

The external RCS environment is ambient atmospheric air inside the Containment Building that is climate controlled. This environment in the Containment Building during normal operations has maximum humidity of 70% and maximum temperature of 120°F. [Reference 1, Table 9-18, Reference 29, Attachments 1, Table 1 page 13]

As a result of the actions taken due to the experience in 1989 and 1994 with minor Pressurizer Heater Sleeve leakage, BGE has replaced or scheduled near-term replacement of high-susceptibility Alloy 600 pressure boundary components. [Reference 14, Section 2] The remaining CCNPP Alloy 600 pressure boundary components are among the least susceptible to PWSCC when compared to other U.S. reactors that have performed inspections of these nozzles. [Reference 14, Section 16.2.7, Figure 6-6]

Group 7 (SCC/IGSCC/PWSCC) - Aging Mechanism Effects

Stress corrosion cracking results from the combined and synergistic interaction of a chemically-aggressive environment, susceptible material, and tensile stress (can be the result of cold working). Over long periods of time SCC occurs as the material fails by slow, environmentally-induced crack initiation and growth that may lead to eventual localized, non-ductile failure. The RCS materials susceptible to SCC are austenitic stainless steel, low-alloy steels, and nickel-based Alloy 600. Several RCS components, such as the pressurizer surge line safe ends, spray nozzle safe ends, pressurizer instrument nozzles, and pressurizer heater sleeves, are particularly susceptible to SCC. [Reference 2, PZV. Valve, Attachments 7s] Understanding of the variables that cause these effects and their interdependencies continues to improve and is the subject of ongoing research by industry worldwide and by NRC.

Intergranular SCC is the preferential dissolution of grain boundary regions with only a slight attack of the grain matrix. The IGSCC aging mechanism requires the presence of high tensile stress, material that is sensitive to attack, and the presence of corrosive anions such as oxygen, chlorides, fluorides, sulfates, and other sulfur ions.

Primary water SCC (in particular, IGSCC) is SCC that occurs in the presence of the RCS (primary side coolant) environment. The PWSCC aging mechanism has been observed in the tube roll transition region of SGs and is a problem for pressurizer instrument nozzles and heater sleeves fabricated from Alloy 600. [Reference 2, SG HX, PZV, Attachments 7s]

Experience to date indicates that cracks for PWSCC of RCS penetrations initiate first in the vicinity of penetrations and then grow axially from the penetration. The resulting cracks are short, grow slowly, grow at comparable rates axially and radially (through-wall), and result in very minimal leakage when through-wall penetration finally occurs. Therefore, safety concerns are minimal. [Reference 55]

The RCS components described above are considered susceptible to SCC, IGSCC, and PWSCC are exposed to an aggressive environment, and are placed under high tensile stresses. [Reference 2, Attachments 6s, 7s] The combined effect of these factors could result in reduction of the ability of the components to maintain the RCS pressure boundary under CLB design loading conditions. Therefore SCC, IGSCC, and PWSCC are plausible ARDMs for this group of components.

Group 7 (SCC/IGSCC/PWSCC) - Methods to Manage Aging

<u>Mitigation</u>: The effects of S , IGSCC, and PWSCC on susceptible materials in the RCS cannot be eliminated, but the effects of these ARDMs can be monitored and actions taken to mitigate the effects. Reactor coolant chemistry controls that minimize dissolved oxygen and halides and sulfur species are also believed to mitigate SCC and IGSCC susceptibility on RCS piping. Sleeving, plating, weld overlays, thermal treatment, and replacement with material less susceptible to SCC can also be used to mitigate or remedy the effects these ARDMs have on RCS components.

Discovery: Stress corrosion cracking (of all kinds) of RCS components can be discovered and monitored by inspection programs. Inspection methods and frequencies can be defined based on susceptibility of the components, and inspection results from other facilities can be used to adjust the predicted susceptibility, inspection methods, and frequency of inspection.

Given the expected axial nature of cracks, the slow growth rates, the minimal leakage that occurs once through-wall penetration does occur, and the low safety concern, periodic inspections of low-susceptibility pressure boundary penetrations for evidence of leakage is sufficient. Dedicated inspection of high-susceptibility pressure boundary and non-pressure boundary components should be considered and be timed based on expected initiation of cracks and expected propagation rates.

Detection of cracks shortly after they have initiated would permit timely repair, long before the intended function is jeopardized, and might minimize the cost and complexity of repair. Ranking models could be used to estimate SCC susceptibility and to schedule inspections based on the potential for crack initiation.

Group 7 (SCC/IGSCC/PWSCC) - Aging Management Program(s)

The CCNPP Alloy 600 Program Plan is credited with both mitigation and discovery of SCC/IGSCC for susceptible RCS piping components (except for the RPV head seal leakage detection line), SCC/IGSCC/PWSCC for susceptible pressurizer components, and SG HX instrument nozzles.

Calvert Cliffs' Alloy 600 Program Plan was developed in response to primary pressure boundary leakage at CCNPP and other plants caused by PWSCC. The CCNPP Alloy 600 Program Plan builds on CCNPP and industry experience and provides for systematic evaluation of Alloy 600 pressure boundary components in the RCS. It addresses nuclear safety concerns and identifies actions to minimize the safety and economic impact of SCC of Alloy 600 components. The program defines mitigation and discovery alternatives, as discussed below, and provides the process for considering susceptibility, safety, and economics in selecting from these alternatives. It also includes measures for monitoring industry experience and making appropriate adjustments based on this experience.

The susceptibility to SCC was evaluated for each CCNPP Alloy 600 nozzle based on ranking models developed by both Westinghouse and CE. A susceptibility index calculated from the Westinghouse model is a function of microstructure, effective stress factor, and temperature factor. The susceptibility index is used to develop a Relative Susceptibility Index, which is the susceptibility index of the component under analysis as compared to the susceptibility index of the reference/benchmark component. The reference component in this case is the CCNPP Unit 2 Pressurizer heater sleeves that developed minor leakage in 1989. The Relative Susceptibility Index is then multiplied by the actual or effective full power hours to obtain a time-dependent Relative Cumulative Susceptibility Index.

The CE model was used for the RCS Alloy 600 nozzles with inputs that were generic to all welded-tube type Alloy 600 nozzles; temperature, time in effective full power hours, and applied stress, which is based on the geometry of penetration and material yield strength. The CE model was used to calculate crack initiation probabilities as a function of effective full power hours. [Reference 14, Section 7].

The calculated susceptibility and crack initiation probability results were used to rank the nozzles and to develop recommendations for inspection, mitigation, repair and/or replacement of the nozzle(s). [Reference 14, Section 8] The susceptibility and economic analyses are used to select from the following options available for nozzles: [Reference 14, Section 9]

- Repair/replace nozzles based on susceptibility assessment;
- Perform mitigating techniques based on susceptibility assessment;
- Continue visually inspecting each nozzle as required by the BACI Program;
- Be prepared to repair nozzles on an as-failed basis. This option requires BGE to have replacement nozzles, repair plans, and design packages ready prior to the discovery of leakage; and
- Perform augmented inspection to find non-throughwall SCC and perform repair/replacement, as necessary.

Nuclear safety, radiation exposure, and economics are considered when selecting mitigating steps or repair/replacement for nozzles susceptible to SCC. Nuclear safety considerations include whether a complete severance of the nozzle due to circumferential cracking could lead to an unisolable small break loss-of-coolant accident, whether stresses would exist that could lead to such circumferential cracking, and whether a nozzle would exhibit minor leakage before crack growth would cause rapidly increasing leakage. [Reference 14, Section 14].

The focus of this program to date has been on pressure boundary components. This is appropriate given their greater stresses and greater potential to initiate design basis events. This program plan will be modified to include RCS nozzles thermal sleeves in addition to those that form the pressure boundary. [Reference 2, Attachment 10] The SG HX tubes are specifically excluded from the scope of the Alloy 600 Program Plan. [Reference 14, Section 1.1]

Mitigation: The effects of SCC/IGSCC will be mitigated for the RCS piping (device code -CC) by CCNPP Technical Procedure CP-204. Maintaining the RCS chemistry with a minimum of impurities will aid in the prevention of these ARDMs. [Reference 2, Attachment 1] For further discussion of CP-204, refer to the Group 5 (IGA) - Aging Management Programs.

The CCNPP Alloy 600 Program Plan lists possible additional mitigation alternatives that include the following techniques: [Reference 14, Section 11]

- Shot peening - This induces compressive residual stress, slowing PWSCC initiation;
- Sleeving - A sleeve of Alloy 690 is rolled and/or welded in existing Alloy 600 sleeves;
- Weld overlay - A thin layer of welded metal with a composition equivalent to Alloy 690 is deposited over the high stress area of the Alloy 600;
- Nickel plating - This technique provides a barrier to the primary water;
- Thermal treatment - Conducted in-situ to reduce residual stress;
- RCS temperature reduction - Reduces the thermodynamic driving force for PWSCC;

- Zinc Injection - Zinc added to the primary water may slow initiation and growth of PWSCC cracks; and

- Mechanical stress improvement - Controlled plastic deformation of the nozzle(s) in a manner that creates compressive residual stresses at locations susceptible to SCC (the technique has been used extensively in Boiling Water Reactor plants on stainless steel pipe fittings, weldments, and nozzles).

If mitigation techniques are not sufficient or are unfeasible, then corrective actions are provided for nozzle(s) repair or replacement. The Alloy 600 Program Plan includes the following options to repair or replace nozzles: [Reference 14, Section 12]

- Local weld repair of defects;

- Replacement with Alloy 690 sleeves;

- Removal from service/plugging of a nozzle; or

- Encapsulate the existing nozzle in an outer nozzle bolted to the vessel to convert the nozzle into a bolted gasketed joint.

Calvert Cliffs Technical Procedure RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation," is credited with the mitigation of SCC on the RPV head seal leakage detection line. The procedure directs the user to blow the RPV head seal leakage detection line (also known as the O-ring seal leak-off line) clear of fluid with compressed air. [Reference 23, Section 6.3] Clearing the line of fluid will greatly reduce the potential for this ARDM. [Reference 2, CC06, Attachments 6] This procedure will be performed after each refueling outage. This program has been considerably upgraded through operating experience, to the point of requiring close inspection for nicks, scratches, and pitting, with documented acceptance criteria for any indications found. These upgrades have been very effective. Calvert Cliffs' reactor vessels are currently operating leak free.

Discovery: Because PWSCC of RCS penetrations is not presently a significant safety concern at CCNPP, the Alloy 600 Program Plan presently focuses its analysis on economic considerations. It assesses the relative susceptibility to PWSCC for each group of RCS nozzles and determines which are at greatest risk of crack initiation.

All RCS Alloy 600 nozzles are inspected each refueling outage for indications of leakage by the BACI Program. [Reference 33] Leakage that develops between refueling outages will be detected before significant through-wall leakage develops as a result of the Technical Specification limits on leakage. The Alloy 600 Program Plan also includes provisions for augmented inspection based on susceptibility.

Reactor Coolant System nozzles are evaluated under the Alloy 600 Program Plan based on primary and secondary factors. The primary evaluation factors for PWSCC susceptibility include: [Reference 14, Section 8]

- Operating temperature;

- Material peak stress level;

- Material heat treatment, if known;

- Number of effective full power hours; and
- Previous industry failures of same material heat.

The secondary PWSCC susceptibility factors include: [Reference 14, Section 8]

- Industry susceptibility rankings;
- Amount and type of machining/rework on a component during fabrication;
- Product form (i.e., bar, tubing, pipe);
- Whether a crevice environment exists;
- Potential for trapping contaminants due to isolation from flow circulation (stagnation);
- History of chemical excursions; and
- General susceptibility of nozzle type.

Susceptibility rankings based on predictive models cannot be used to predict the exact timing of crack initiation or progression through-wall. Primary water SCC initiation times for identical materials vary over a wide band, and predictive models take into account a limited number of parameters. Detailed study of material properties, fabrication, and service history is required to assess susceptibility of individual nozzles. However, the susceptibility models are used to allow susceptibility comparison. The CE model is used in the economic analysis to determine the optimal time for augmented inspections, but not as the basis for safety evaluations. [Reference 14, Section 7]

The susceptibility model results are used for analyzing nozzles to determine when to perform augmented inspections for crack initiation. Alternatives for augmented nozzle inspections include eddy current, dye penetrant, and ultrasonic examination. [Reference 14, Section 10]

Relevant operating experience applicable to PWSCC includes failure of purification system resin retention screens. This resulted in a resin intrusion of the Unit 1 RCS in March 1989. Resin decomposition products may contribute to cracking of sensitized Alloy 600 and the evaluation of the 1989 event concluded that prompt actions were taken to minimize the deviation and RCS temperature and to remove the resin and its decomposition products. [Reference 18]

Alloy 600 PWSCC has occurred at CCNPP and at other domestic and foreign PWRs and BGE has been a leader in industry efforts to understand and manage PWSCC. [Reference 14, Section 3] The Alloy 600 Program Plan is a relatively new program, having been initiated in 1992. Since this program achieved its present form in 1995, no pressure boundary leakage has occurred as a result of PWSCC. Some RCS components have been replaced and some have been nickel plated as a result of the program.

The Alloy 600 Program Plan includes specific provisions for monitoring industry experience and adjusting the plan accordingly. Calvert Cliffs MN-3-304, Control of the Alloy 600 Program Plan establishes administrative controls for this program under the site procedures hierarchy. The Alloy 600 Program Plan will continue to examine pressure-boundary components susceptible to PWSCC to ensure that these components maintain their intended function required by the CLB during the period of extended operation. The program will be modified to include RCS nozzle thermal sleeves. [Reference 2, Attachments 10]

Calvert Cliffs' BACI Program is credited with the discovery of SCC/IGSCC on the external surfaces of RCS piping (pipe code -GC) studs/nuts, and SCC on RCS valve bolting. This procedure requires investigation of any boric acid leakage that is found. [Reference 2, Attachment 1] Refer to the discussion of the BACI Program in Group 2 (wear) - Aging Management Programs.

Technical Procedures STP-M-574-1/2 are credited for discovering of SCC/PWSCC on SG HX tubes. The procedure directs the user as to the sample size for tube inspection, inspection process, evaluation, and determination of tube status. Refer to the discussion of the SG Eddy Current examination program in Group 2 (wear) under Aging Management Programs.

Calvert Cliffs Administrative Procedure MN-3-110 is credited with discovering SCC on the external surfaces of RCS piping components (pipe code -CC). Visual examination (VT-2) of external surfaces are performed for the RCS components in accordance with ASME Section XI IWA-2212. The ISI Program was previously discussed in Group 2 (wear) under Aging Management Programs.

Technical Procedure FASTENER-01, "Torquing and Fastener Applications," is credited with discovering SCC on SG HX bolting studs. The procedure is used whenever studs are detensioned and retensioned on the SGs during plant refueling outages. This procedure directs the user to perform a visual inspection of the fasteners for damage and corrosion. If fasteners are acceptable they are reused, otherwise they are replaced. [Reference 56, Sections 6.2, 6.3]

Group 7 (SCC/IGSCC/PWSCC) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions ca.. be reached with respect to SCC, IGSCC, and PWSCC of the Group 7 components:

- The pressurizer components are susceptible to SCC/IGSCC/PWSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The piping components listed are susceptible to SCC/IGSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The SG components listed are susceptible to SCC/PWSCC/IGSCC and provide the RCS pressure-retaining boundary. These components must maintain their integrity under CLB design loading conditions.
- The valve components listed are susceptible to SCC and provide the RCS pressure-retaining boundary and containment isolation function. These components must maintain their integrity under CLB design loading conditions.
- Although susceptibility to PWSCC is low relative to most other plants, PWSCC is plausible for some of the Group 7 components mentioned above, and could impair their ability to perform their intended function.

- The NRC, industry, and BGE have concluded that PWSCC axial cracking is not a safety concern and that circumferential cracking that would not be detected before it is a safety concern is not likely.
- Calvert Cliffs' Alloy 600 Program Plan provides for actions to assess SCC/PWSCC/IGSCC susceptibility and take action to mitigate, inspect, repair, or replace only Alloy 600 components based on the results. It schedules augmented inspections when crack initiation is likely.
- Calvert Cliffs' Alloy 600 Program Plan also includes provisions for monitoring and incorporating industry experience. The Alloy 600 Program Plan will be modified to include thermal sleeves installed in the RCS nozzles.
- Calvert Cliffs Technical Procedure CP-204 will mitigate the effects of SCC and IGSCC for the RCS piping components (except the RPV head seal leakage detection line) by maintaining primary system chemistry conditions such that impurities will be minimized, and contains acceptance criteria that ensures corrective actions will be taken to ensure timely correction of adverse chemistry parameters.
- Calvert Cliffs' BACI Program provides for examination of the RCS external surfaces and discovery of any SCC/IGSCC on RCS piping components and SCC on RCS valve components. The program also provides for subsequent cleanup for any boric acid leakage that is found.
- Calvert Cliffs Technical Procedure RV-78 is credited with the mitigation of SCC of the RPV head seal leakage detection line by clearing the line of stagnant fluid with compressed air.
- Calvert Cliffs Technical Procedures STP-M-574-1/2 are credited for discovering outside diameter initiated IGSCC and PWSCC on the SG HX tubes. An IR is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure.
- Calvert Cliffs' ISI Program, per the requirements of ASME Section XI, is credited with the discovery of SCC and IGSCC on the external surfaces of RCS piping components. Though SCC/IGSCC cannot be completely prevented, the status of the components can be evaluated on a regular basis and corrective actions can be taken as conditions indicate SCC.
- Calvert Cliffs Technical Procedure FASTENER-01 is credited for discovering SCC on SG HX primary manway bolting studs.

Therefore, there is reasonable assurance that the effects of SCC, IGSCC, and PWSCC will be managed in order to maintain the RCS intended functions under all conditions required by the CLB during the period of extended operation.

Group 8 (thermal embrittlement) - Materials and Environment

Table 4.1-3 shows that thermal embrittlement is plausible for some of the RCS device types. These susceptible RCS device types and their material characteristics are: [Reference 2, -CC-01/05, PUMP-01, PZV-01, Attachments 4, 5, 6]

- -CC - surge pipe, surge elbows; surge nozzle safe end, shutdown cooling nozzle safe end, safety injection nozzle safe end (CASS);
- PUMP - (RCP) case and pump cover (CASS); and

- PZV - surge nozzle safe end (CASS).

The RCS internal environment (primary side) is that of chemically-treated borated water at an operating pressure of approximately 2250 psia. The RCS operating temperatures are not greater than 548°F in the cold leg and a maximum of approximately 600°F in the hot leg. The RCS maintains a flow rate of approximately $134x10^6$ lbm/hr. [Reference 1, Section 4.1.1, Table 4-1] The RCS also contains chemicals for controlling reactor power (boric acid) and corrosion control. The RCS components listed are subject to thermal and mechanical cyclic loading during RCS heat-up and pressurization.

Group 8 (thermal embrittlement) - Aging Mechanism Effects

Cast austenitic stainless steel material is susceptible to thermal embrittlement mechanisms in a high temperature environment. Thermal embrittlement is the loss of fracture toughness caused by the thermally-induced changes in the formation and distribution of alloying constituents. Ferrite-containing stainless steel are susceptible, as are materials with grain boundary segregation of impurities. [Reference 2, Valve, Attachments 7]

Fracture toughness is a measure of a material's resistance to fracture in the presence of a previously existing crack. Generally, a material is considered to have adequate fracture toughness if it can withstand loading to its design limit in the presence of detectable flaws under stated conditions of stress and temperature. The CASS thermal embrittlement mechanisms are both time and temperature dependent. The maximum rate of embrittlement for CASS occurs at 885°F ± 45°F. At lower temperatures the embrittlement rate is less, but the effects of thermal embrittlement have been observed at temperatures as low as 500°F to 650°F. [Reference 57, Section 4.2; Reference 58, Enclosure 2, Item 10]

In addition to temperature, thermal embrittlement is dependent on the CASS material alloy composition. High molybendum and carbon content contribute to thermal embrittlement susceptibility. Equally important is the casting process used to fabricate the component. Centrifugally-cast components are more resistant to thermal embrittlement than statically-cast components. [Reference 2, Attachments 7, Valve, Reference 57, Section 4.2]

For centrifugally-cast component parts with delta ferrite content below 20%, mechanical properties are not degraded significantly by the thermal embrittlement process. For statically-cast component parts with molybendum content such that it meets casting grade CF3 or CF8 limits, the 20% delta ferrite threshold also applies. However, for statically-cast component parts with molybendum content above that meeting CF3 or CF8 limits, 14% delta ferrite is the threshold below which no significant degradation due to thermal embrittlement is observed. Therefore, thermal embrittlement is potentially significant for: [Reference 57, Section 4.2]

- Centrifugally-cast component parts, with a delta ferrite content above 20%;
- Statically-cast component parts, with molybendum content meeting CF3 and CF8 limits and with a delta ferrite content above 20%; and
- Statically-cast component parts, with molybendum content exceeding CF3 and CF8 limits and with a delta ferrite content above 14%.

This aging mechanism, if unmanaged, could eventually result in a loss of material fracture toughness such that the Group 8 components may not be able to perform their intended function under CLB conditions. Therefore, thermal embrittlement was determined to be a plausible ARDM for which the aging effects must be managed for the Group 8 components.

Group 8 (thermal embrittlement) - Methods to Manage Aging

Mitigation: There are currently no methods of mitigating the effects of thermal embrittlement other than proper material selection and by replacing susceptible components with components constructed of non-susceptible materials. Use of non-CASS components (e.g., forged stainless steel), or use of CASS components with delta ferrite content below the threshold values shown above, would make this ARDM non-plausible.

Discovery: A program that would analyze those RCS components that are susceptible to thermal embrittlement could determine if those components are able to maintain their intended function during the license renewal period. As noted in the Material and Environment section above, some of the Group 8 hand valves may have forged (i.e., not cast) stainless steel bodies/bonnets. Walkdowns can be performed to visually exam the components or gather specific manufacturer and model number information in order to determine whether the components are of forged or cast construction. For components that are determined to be of cast construction, analysis can be performed (e.g., determination of delta ferrite content) to determine if valves have adequate fracture toughness based on their material properties.

Group 8 (thermal embrittlement) - Aging Management Program(s)

Mitigation: There are no methods to prevent thermal embrittlement; therefore, there are no programs for the mitigation of this ARDM.

Discovery: A new program will be developed to manage the effects of thermal embrittlement by identifying those components that may not be able to perform their intended function due to the effects of thermal embrittlement. The CASS Evaluation Program will be based on two alternatives. The first alternative will be a delta ferrite and flaw tolerance analysis. This analysis will be performed on a case-by-case basis using actual material data and the procedure outlined in NUREG/CR-6177, Assessment of Thermal Embrittlement of Cast Stainless Steels," and NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR *[Light Water Reactor]* Systems." The flaw tolerance analysis will use the procedures from ASME Nuclear Code Case N-481. The intent of the analysis will be to determine if the respective valve has adequate fracture toughness, based on its material properties, in order to be capable of performing its pressure boundary function under CLB conditions. [Reference 2, Attachments 10]

The second alternative will be to replace the components with those that contain no CASS. The second alternative will be used if a component cannot be qualified for the license renewal term under the first alternative, or if it is more cost effective to replace rather than perform an analysis. Replacement of the component will make the ARDM as non-plausible for the respective component. [Reference 2, Attachments 10]

The corrective actions taken as part of the CASS Evaluation Program will ensure that the Group 8 components remain capable of performing their pressure boundary function under all CLB conditions.

Group 8 (thermal embrittlement) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 8 components subject to thermal embrittlement:

- The Group 8 components have the passive intended functions to maintain the RCS pressure boundary and containment isolation under CLB design loading conditions.
- Thermal embrittlement is plausible the Group 8 components which, if unmanaged, could eventually result in a loss of fracture toughness such that the Group 8 components may not be able to perform their pressure boundary function under CLB conditions.
- Calvert Cliffs' CASS Evaluation Program will perform analysis to determine if the RCS components in question have adequate fracture toughness in order to perform their pressure boundary function under CLB design loading conditions. Alternatively, the CASS Evaluation Program will replace susceptible components with components that contain no CASS, thus making the ARDM non-plausible.

Therefore, there is reasonable assurance that the effects of thermal embrittlement will be managed in order to maintain the RCS intended functions under all conditions required by the CLB during the period of extended operation.

4.1.3 Conclusion

The programs discussed for the RCS components are listed on the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the RCS components will be maintained, consistent with the CLB during periods of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 4.1-4

LIST OF AGING MANAGEMENT PROGRAMS FOR THE RCS

	Program	Credited As
Existing	CCNPP "Eddy Current Exam of CCNPP Unit 1 SG," and , "Eddy Current Exam of CCNPP Unit 2 SG," (STP-M-574-1/2)	Discovery of the effects of denting (Group 1), wear (Group 2), pitting on SG tubes (Group 5), and SCC (Group 7).
Existing	CCNPP "Pressurizer Manway Cover Removal and Installation," (RCS-10)	Discovery of the effects of wear (Group 2) on pressurizer studs, nuts, and seating surfaces.
Existing	CCNPP "SG Secondary Manway Cover Removal and Installation" (SG-1/2); "Steam Generator Secondary Handhole Cover Removal" (SG-5); and "Steam Generator Secondary External Handhole Cover Installation" (SG-6)	Discovery of the effects of wear (Group 2) on SG closure surfaces.
Existing	CCNPP "RCS Leakage Evaluation" (STP-O-27-1/2)	Discovery of the effects of wear (Group 2).
Existing	CCNPP "Use of Operating Experience and the Nuclear Hotline" (NS-1-100)	Discovery of the effects of wear (Group 2) on RCP tube-in-tube seal water HX through a continuing review of industry experience.
Existing	CCNPP "SG Primary Manway Cover Removal and Installation" (SG-20)	Discovery of the effects of wear (Group 2) and general corrosion (Group 5) on the primary side of the SG manway and seating surfaces.
Existing	CCNPP "Inservice Inspection of ASME Section XI Components" (MN-3-110)	Discovery, per ASME XI, of the effects of wear (Group 2), erosion corrosion (Group 3), general and galvanic corrosion (Group 5), SCC and IGSCC (Group 7) on those RCS components susceptible to these ARDMs.
Existing	CCNPP BACI Program (MN-3-301)	Discovery and mitigation of the effects of wear (Group 2), erosion (Group 3) galvanic/general corrosion (Group 5), and SCC/IGSCC (Group 7).

	Program	Credited As
Existing	CCNPP "Specifications and Surveillance for Component Cooling/Service Water System" (CP-206)	Mitigation of the effects of IGA (Group 6) on the RCP seal water HXs.
Existing	CCNPP "Specification and Surveillance Primary Systems" (CP-204)	Mitigation of the effects of IGA (Group 6) and SCC, IGSCC, and PWSCC (Group 7) on RCS components.
Existing	CCNPP Torquing and Fastener Applications (FASTENER-01)	Discovery of the effects of SCC (Group 7) on RCS fasteners. Those fasteners that are non-acceptable are replaced.
Existing	CCNPP RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation"	Mitigation of the effects of SCC (Group 7) on the RPV head closure seal leakage detection line.
Modified	CCNPP FMP	Discovery of the effects of low-cycle fatigue (Group 4). The FMP will be modified to perform an engineering evaluation for the RCPs, MOVs, and pressurizer RVs to ensure that the components are bounded by existing critical locations and controlling transients. If they are not bounded they will be added to the FMP.
Modified	CCNPP Alloy 600 Program	Discovery and mitigation of the effects of SCC, IGSCC, and PWSCC (Group 7), and will be modified to include the RCS nozzle thermal sleeves.
New	CASS Evaluation Program	Discovery and management of the effects of thermal embrittlement (Group 8).

4.1.4 REFERENCES

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30. "Inservice Inspection Program Plan for the Second Inspection Interval for Calvert Cliffs Nuclear Power Plant Units 1 & 2," Southwest Research Institute Project 17-1168, November 1987, Revision 0, Change 6, November 11, 1996

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ATTACHMENT (2)

APPENDIX A - TECHNICAL INFORMATION

5.11A - AUXILIARY BUILDING HEATING AND VENTILATION SYSTEM

5.11A Auxiliary Building Heating and Ventilation System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA) addressing the Auxiliary Building Heating and Ventilation (H&V) System. The Auxiliary Building H&V System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire BGE LRA.

5.11A.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to aging management review (AMR) begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Representative historical operating experience pertinent to aging is included in appropriate areas, to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets and through documented discussions with currently assigned cognizant CCNPP personnel.

Section 5.11A.1.1 presents the results of the system level scoping, 5.11A.1.2 the results of the component level scoping, and 5.11A.1.3 the results of scoping to determine components subject to an AMR.

5.11A.1.1 System Level Scoping

This section begins with a description of the system, which includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

System Description/Conceptual Boundaries

The Auxiliary Building H&V System is comprised of fans, air handling units, dampers, filters, coolers, controls, and ductwork, which provide air, in some cases filtered and tempered, to various rooms in the auxiliary and radwaste buildings. A negative pressure, with respect to ambient and surrounding areas of the building, is normally maintained in the Auxiliary Building to ensure that clean areas do not become contaminated through the ventilation system. Areas serviced by the system include the Switchgear Rooms (each unit), Diesel Generator Rooms (three total), Auxiliary Feedwater (AFW) Pump Room (each unit), Service Water (SRW) Heat Exchanger Room (each unit), main steam line penetration area (each unit), waste processing area (each unit), Emergency Core Cooling System (ECCS) Pump Rooms (each unit), the fuel handling areas (shared between units), and general areas of the Auxiliary Building. Exhaust air from the waste processing areas, ECCS Pump Rooms, and the fuel handling areas is passed through a roughing filter and a high efficiency particulate (HEPA) filter to remove potentially radioactive particulate contamination prior to discharge through the plant vent. Exhaust air from the ECCS Pump Room and the fuel handling area can also be routed through separate charcoal filters to remove radioactive iodine in the event of a loss-of-coolant accident or fuel handling incident, respectively. [References 1 through 5]

The Switchgear Rooms are cooled the year round by redundant heating, ventilating, and air conditioning (HVAC) units and refrigeration systems. The air conditioning system provides conditioned air for cooling and ventilation. A set of mixing dampers automatically proportion the amount of fresh air and recirculated air as needed to maintain room temperature within design limits. The HVAC units and refrigeration components are redundant, but the supply and return ducts to the Switchgear Room are not. [References 1, 4, and 5]

The Fairbanks Morse diesel generators are housed in three separate rooms in the Auxiliary Building. Heat output from each generator is sufficiently high that cooling must be provided for both summer and winter. The ventilation system for this area is designed to limit room temperature to a maximum of 120°F in summer and a minimum of 60°F in winter. Outside air is used as the cooling medium. An air-handling unit and mixing box-damper arrangement proportion the flow of outside air and recirculated air according to room temperature. When the emergency diesel generator (EDG) is running, its room is pressurized and the excess air is forced out through a weatherproof exhaust opening over the outside door. Hot water unit heaters maintain a minimum temperature of 60°F when the diesel is shut down. [References 1 and 4] Heating and ventilation for the additional EDGs, which are located in a separate building outside, are discussed in the Control Room HVAC System Evaluation in Section 5.11C of this application.

There are "normal" and "emergency" air cooling systems for the AFW Pump Room. During normal plant operation, one self-contained HVAC unit maintains the temperature in this room at 90°F or below. During the emergency mode of operation, which would exist if the normal HVAC unit fails for any reason, redundant fans circulate air between these two rooms through a system of connecting ductwork. The heat sink effect of the equipment room supplies all of the cooling required to prevent the room air temperature from rising above 130°F, provided administrative operational restrictions are followed, to prevent failure of the air-cooled bearings of the pumps while they are operating. [References 1, 4, and 5]

The SRW Heat Exchanger Room is provided with forced air ventilation by separate supply and exhaust fans and dampers. The ventilation is required to remove equipment heat and maintain the room temperature low enough for equipment operability in post-accident situations. Relatively cool air is drawn from the Turbine Building and the warmer exhaust air is returned there, as well. The dampers automatically shut upon high pressure to isolate the room from temperature rises due to a high energy line break inside of the Turbine Building. [References 6 and 7]

Heat released by the main steam and feedwater pipes requires that cooling be provided in the main steam line penetration area all year round. This system uses outside air as the cooling medium. Fresh air is mixed with recirculated air as required and supplied through ducting from an air-handling unit. The main steam line penetration area is pressurized and the excess air flows out through the open safety vent to the roof. A room thermostat controls the position of the mixing dampers, which are located upstream of dust-stop filters. [References 1, 4, and 5]

A negative pressure with respect to ambient and surrounding areas of the building is normally maintained in the waste processing area. A common air supply system consisting of three 50% capacity air handling units supplies outdoor air for ventilation of the common waste processing area and general areas in the Auxiliary Building. A system of ductwork ensures a uniform distribution throughout this area. The exhaust system draws air from the waste processing areas by means of ductwork and forces it through HEPA filters, after which it is discharged into the main exhaust plenums. From here, the main plant exhaust fans force the air past the radioactivity monitors and out through the exhaust stacks. These exhaust fans are 100% redundant, but the filters are not. [References 1 and 3]

The ECCS Pump Rooms require ventilation to limit room temperature and provide proper cooling of the safety injection and containment spray pumps. The subsystem consists of one cooling unit for each ECCS Pump Room, cooling unit fans, and an ECCS Pump Room exhaust system that includes a roughing filter, a HEPA filter, charcoal filter, and dampers. The Saltwater System provides cooling to the cooling unit. [References 1 and 3]

Two 50% capacity air handling units provide filtered air to the fuel handling area, which includes the spent fuel pool area, New Fuel Storage Room, and the Miscellaneous Waste Evaporator Room. A separate exhaust system draws air through a manifold and HEPA filters and feeds it into the main plant vent of Unit 1. During load handling evolutions over the spent fuel pool that includes moving fuel, this air is diverted through charcoal filters after it leaves the HEPA filters for removal of radioactive iodines prior to discharge to minimize radioactive material release in the event of a fuel handling accident. The exhaust fans are capable of maintaining a negative pressure with respect to ambient and surrounding areas of the building. Unit heaters are provided to maintain a minimum temperature of 60°F in the winter. [References 1 and 3]

System Interfaces

The Auxiliary Building H&V System has an interface with the following systems and components: [References 2 through 5; Reference 8]

System/Component	Within the Scope of License Renewal at the Interface?
Main Plant Vent	No
Control Room HVAC System	Yes, See Section 5.11C of the BGE LRA
Radiation Monitoring System	No
Saltwater Cooling System	Yes, See Section 5.16 of the BGE LRA
Service Water System	No

System Scoping Results

The Auxiliary Building H&V System is within the scope of license renewal based on 10 CFR 54.4(a). The following intended functions of the Auxiliary Building H&V System were determined based on the requirements of §54.4(a)(1) and (2), in accordance with the CCNPP IPA Methodology, Section 4.1.1: [Reference 9, Table 1]

- To supply air to the battery ventilation system in response to a Design Basis Event (DBE);
- To initiate letdown line isolation to provide radiological release control during a loss-of-coolant accident;
- To provide ventilation for, and remove potentially radioactive contamination from, the ECCS Pump Room in response to a DBE;

- To provide HVAC for, and remove potentially radioactive contamination from, the Fuel Handling area in response to a DBE;
- To provide HVAC to the Electrical Switchgear Room in response to a DBE;
- To provide ventilation to the Diesel Generator Rooms in response to a DBE;
- To provide ventilation to the AFW Pump Room in response to a DBE;
- To provide ventilation to the SRW Heat Exchanger Room in response to a DBE;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To maintain structural integrity to support proper operation of other Auxiliary Building H&V System components.

The following Auxiliary Building H&V System intended functions were determined based on the requirements of §54.4(a)(3): [Reference 9, Table 1]

- For fire protection (§50.48)- To provide alternate ventilation to the AFW Pump Room during a fire; and
- For environmental qualification (§50.49)- To maintain functionality of electrical equipment as addressed by the Environmental Qualification Program and to provide information used to assess the plant and environs condition during and following an accident.

All components of the Auxiliary Building H&V System that meet the fire protection or environmental qualification criteria of 54.4(a)(3) are also safety-related. No components were scoped that only meet a 54.4(a)(3) criteria.

Components of the Auxiliary Building H&V System that support the above functions are safety-related and Seismic Category 1 and are subject to the applicable loading conditions identified in the Updated Final Safety Analysis Report Section 5A.3.2 for Seismic Category 1 systems and equipment design. [References 3 through 6; Reference 10] The ductwork was constructed of galvanized copper bearing sheet steel, which conformed to the latest Guide from the American Society of Heating, Refrigeration, and Air Conditioning Engineers. It was installed in accordance with high velocity and low velocity duct construction standards from the Sheet Metal and A/C Contractors National Association. [Reference 11]

Operating Experience

Over 20 years of operating experience has shown the H&V systems at CCNPP to be highly reliable in maintaining their passive functions. Some cracking has been discovered in HVAC ducting due to vibration-induced fatigue. However, these isolated failures were due to a combination of design and installation deficiencies. In one case, additional supports were added to the ducting to prevent recurrence. In another case, the fans were balanced to minimize the vibration. Some loosening of fasteners has been experienced due to dynamic loading. Vibration-related aging concerns are minimized through system design and existing maintenance practices, which are further described below in the discussion for Group 3. Vibration isolators, i.e., flexible collars or cloth boots, are installed around the fans to minimize the vibration being transferred to other equipment. [Reference 2, Attachments 6] Furthermore, fans are monitored for vibration whenever the fan belts are retensioned or replaced.

In 1980, a Control Room air conditioning unit was placed out-of-service to repair broken damper linkages. This failure was caused by excessive wear due to inadequate lubrication of the damper linkage. The existing preventive maintenance (PM) procedure was modified to include lubrication along with the periodic visual inspection. [Reference 12] During performance of these periodic inspections, elastomer degradation of the seals has also been identified. If the seals on jambs or blade edging lose their resiliency or are deteriorated, corrective actions are taken to have the seals replaced. [Reference 13]

Corrosion has been discovered in the housing below the cooling coils in some of the HVAC units. These areas have been inspected to assess the corrosion rates and adequacy of the system pressure boundary. Other than the limited extent of degradation experienced due to vibration, wear, and corrosion, no other significant aging concerns have been identified that could affect the ability of the Auxiliary Building H&V System components to perform their passive intended functions.

5.11A.1.2 Component Level Scoping

Based on the intended system functions listed above, the portions of the Auxiliary Building H&V System that are within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrumentation), and their supports. Safety-related portions of the Auxiliary Building H&V System include the following: [References 3 through 5; Reference 10]

Plant Area	Portion Within Scope
Switchgear Room	Entire subsystem including HVAC units, refrigeration system, and supply and return duct and dampers
Diesel Generator Rooms	Entire subsystem including supply duct, dampers and fans, and the exhaust dampers
AFW Pump Rooms	Supply duct and dampers and exhaust fans, duct and dampers (the normal A/C unit, and associated duct and damper is not)
SRW Heat Exchanger Rooms	Entire subsystem including supply fan, dampers and duct, and exhaust fan and dampers
Main steam line penetration area	None
Waste processing area	None
ECCS Pump Room	Exhaust path including fans, HEPA filters, charcoal filters, duct, and dampers (exhaust duct from the downstream side of the exhaust fan discharge damper to the plant vent is not)
Fuel handling area	Exhaust fans, HEPA filters, charcoal filters, duct, and dampers (all supply fans, HVAC units, filters, duct, and dampers are not, exhaust duct from the wall of the fuel handling area Exhaust Fan Equipment Room to the plant vent is also not)

APPENDIX A - TECHNICAL INFORMATION
5.11A - AUXILIARY BUILDING HEATING AND VENTILATION SYSTEM

The following 46 device types in the Auxiliary Building H&V System were designated as within the scope of license renewal because they have at least one intended function [Reference 2, Section 3.2 and Table 3-2]:

Device Type	Device Description	Device Type	Device Description
ACC	Accumulator	MD	125/250VDC Motor
CKV	Check Valve	MO	Motor Operator
COIL	Coil	PDI	Pressure Diff Indicator
COMP	Compressor	PDIS	Pressure Diff Indicator Switch
CV	Control Valve	PI	Pressure Indicator
DAMP	Damper	PNL	Panel
DISC	Disconnect Switch/Link	PO	Piston Operator
DRY	Air Dryer	PS	Pressure Switch
DUCT	HVAC Duct	PT	Pressure Transmitter
FAN	Fan	PY	Pressure Converter (Relay)
FL	Filter	RV	Relief Valve
FU	Fuse	RY	Relay
GD	Gravity Damper	SV	Solenoid Valve
HD	Manual Damper	TC	Temperature Controller
HS	Handswitch	TCV	Temperature Control Valve
HV	Hand Valve	TE	Temperature Element
HX	Heat Exchanger	TIC	Temperature Indicating Controller
HY	Converter/Relay	TS	Temperature Switch
JD	Tubing with Piping Code of "JD"	TT	Temperature Transmitter
JL	Power Lamp Indicator	TY	Temperature Device (Relay)
LY	Level Device (Relay)	ZC	Position Controller
M	480V Motor (Feed from MCC)	ZL	Position Indicating Lamp
MB	480V Motor	ZS	Position Switch

Some components in the Auxiliary Building H&V System are common to many other plant systems and have been included in separate sections of the BGE LRA that address those components as commodities for the entire plant. These components include the following: [Reference 2, Section 3.2]

- Structural supports for ducting, piping, cables, and components are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of this application.
- Electrical control and power cabling are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of this application. This commodity evaluation completely addresses the passive intended function entitled "maintain electrical continuity and/or provide protection of the electrical system" for the Auxiliary Building H&V System.
- Instrument tubing and piping and the associated supports, instrument valves, and fittings (generally everything from the outlet of the final root valve up to and including the instrument), and the pressure boundaries of the instruments themselves, are all evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA.

5.11A.1.3 Components Subject to AMR

This section describes the components within the Auxiliary Building H&V System that are subject to AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following Auxiliary Building H&V System functions were determined to be passive: [Reference 2, Table 3-1]

- Maintain the pressure boundary of the system (liquid and/or gas);
- Maintain electrical continuity and/or provide protection of the electrical system; and
- Maintain structural integrity to support proper operation of other Auxiliary Building H&V System components.

Device Types Subject to AMR

Of the 46 device types within the scope of license renewal; [Reference 2, Table 3-2 and Appendix B; Reference 14]

- Twenty-five device types have only active functions and do not require AMR; coil, control valve, disconnect switch/link, fuse, hand switch, converter/relay, power lamp indicator, level device (relay), 480V motor (feed from MCC), 480V motor, 125/250VDC motor, motor operator, piston operator, pressure transmitter, pressure converter (relay), relay, temperature controller, temperature element, temperature indicating controller, temperature switch, temperature transmitter, temperature device (relay), position controller, position indicating lamp, and position switch.
- Ten device types do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly whose only passive function is closely linked to active performance as discussed below; accumulator, air dryer, compressor, tubing with piping Code of "JD," pressure indicator, pressure switch, check valve, relief valve, solenoid valve, and temperature control valve.

  In accordance with the provisions of Section 6.1.1 of the CCNPP IPA Methodology, components that comprise the refrigeration units do not require a specific evaluation of ARDMs because the detrimental effects of aging mechanisms can be observed by detrimental changes in the performance characteristics or condition of refrigeration unit components if they are properly monitored. Therefore, by adequately monitoring these performance or condition characteristics, the effects of aging on the passive intended function are also adequately managed. The active functions are monitored by: (1) operational requirements that must be satisfied for continued plant operation; (2) Maintenance Rule system performance monitoring; and (3) component-specific condition monitoring addressed under the CCNPP Maintenance Program. [Reference 2, Appendix B]

  The ten device types listed above are entirely included in these complex assemblies. Three other device types, i.e., hand valves, heat exchangers, and fans, include some components that are part of these complex assemblies and some that are included in the AMR presented herein.

- Two devices types are evaluated in another section of this application;
  - 'Panel' is evaluated for the effects of aging in the Electrical Commodities Evaluation in Section 6.2 of this application. This commodity evaluation completely addresses the passive intended function entitled "maintain structural integrity to support proper operation of other Auxiliary Building H&V System components"
  - 'Pressure differential indicator switch' is evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of this application.

The remaining nine device types listed in Table 5.11A-1 are subject to a detailed evaluation of aging mechanisms as part of the AMR and are included in this section. For AMR, some device types have a number of groups associated with them because of the diversity of materials used in their fabrication or differences in the environments to which they are subjected.

Maintenance of the pressure boundary of the system is the only passive intended function associated with the Auxiliary Building H&V System not addressed by one of the commodity evaluations referred to above. Therefore, only the pressure-retaining function for the nine device types listed in Table 5.11A-1 is considered in the AMR for the Auxiliary Building H&V System. Unless otherwise annotated, all components of each listed device type are subject to AMR.

TABLE 5.11A-1

AUXILIARY BUILDING H&V SYSTEM DEVICE TYPES REQUIRING AMR

Damper
HVAC Duct
Fan (1)
Filter
Gravity Damper
Manual Damper
Hand Valve (1, 2)
Heat Exchanger (1)
Pressure Differential Indicator (2)

(1) The fans (condenser fans), heat exchangers (condenser and cooling coils of the HVAC unit), and hand valves that are part of the Switchgear Room refrigeration unit are not evaluated herein because they are part of a complex assembly whose only passive function is closely linked to active performance as permitted in Section 6.1.1 of the CCNPP IPA Methodology.

(2) The equalization valve (hand valve) and pressure differential indicator switch for the ECCS Pump Room exhaust HEPA filters are evaluated in the Instrument Line Commodity Evaluation in Section 6.4 of this application. [Reference 9, Attachment 4A]

5.11A.2 Aging Management

A list of potential age-related degradation mechanisms (ARDMs) identified for the Auxiliary Building H&V System components is given in Table 5.11A-2. The plausible ARDMs are identified in the Table by a check mark (✓) in the appropriate device type column. A check mark indicates that the ARDM applies to at least one group for the device type listed. For efficiency in presenting the results of the evaluations in this section, ARDM/device type combinations are grouped together where there are similar characteristics, and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.11A-2 identifies the group in which each ARDM/device type combination belongs.

The following groups have been selected for the Auxiliary Building H&V System:

Group 1 - Includes crevice corrosion, general corrosion, and pitting for duct and heat exchangers.

Group 2 - Includes elastomer degradation and wear for non-metallic duct and damper parts.

Group 3 - Includes dynamic loading for fans.

TABLE 5.11A-2

POTENTIAL AND PLAUSIBLE ARDMs FOR THE AUXILIARY BUILDING H&V SYSTEM

	Auxiliary Building H&V System Device Types								
Potential ARDMs	DAMP	DUCT	FAN	FL	GD	HD	HV	HX	PDI
Cavitation Erosion									
Corrosion Fatigue									
Crevice Corrosion		√ (1)						√ (1)	
Dynamic Loading			√ (3)						
Erosion Corrosion									
Fatigue									
Fouling									
Galvanic Corrosion									
General Corrosion		√ (1)						√ (1)	
Hydrogen Damage									
Intergranular Attack									
Microbiologically-Induced Corrosion									
Particulate Wear Erosion									
Pitting		√ (1)						√ (1)	
Radiation Damage									
Elastomer degradation		√ (2)			√ (2)	√ (2)			
Selective Leaching									
Stress Corrosion Cracking									
Stress Relaxation									
Thermal Embrittlement									
Wear		√ (2)			√ (2)	√ (2)			

√ - indicates that the ARDM is plausible for component(s) within the device type
(#) - Indicates the Group in which this device type/ARDM combination is evaluated

Note: Not every component within the device types listed here may be susceptible to a given ARDM. This is because components within a device type are not always fabricated from the same materials or subjected to the same environments. Exceptions for each device type will be indicated in the aging management section for each ARDM discussed in this report.

APPENDIX A - TECHNICAL INFORMATION
5.11A - AUXILIARY BUILDING HEATING AND VENTILATION SYSTEM

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion on materials and environment, aging mechanism effects, methods to manage aging, aging management program(s), and aging management demonstration.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Materials and Environment

Group 1 is comprised of components that are potentially exposed to moist air and condensation. These include the ducting where the steel materials are exposed to the potentially moist air. The duct, fittings, doors, and door hinges/latches are constructed of galvanized carbon steel. The joint angles are constructed of carbon steel, and the bolts and rivets are plated carbon steel. The supply and exhaust registers are constructed of either enameled carbon steel or aluminum. Group 1 ducting includes all of the Auxiliary Building H&V System duct that is within the scope of license renewal. Some of the components' surfaces are painted or galvanized. [Reference 2, Attachments 4 and 6]

Also included in Group 1 is the galvanized carbon steel housing for the Switchgear Room cooling coils that may be exposed to moist air and condensate from the coils. If the drains become plugged, there may also be standing water in the drain pan that could spill over onto other sections of the equipment base. The coils themselves have the system pressure boundary intended function; however, they do not require AMR because they are part of the refrigeration units and considered a complex assembly, as discussed in Section 5.11A.1.2. [Reference 2, Attachments 4 and 6]

The Auxiliary Building H&V System is designed to maintain the temperatures inside each of the ventilated areas, assuming the outdoor air temperature is 95°F, below the design temperature as follows: [Reference 1, Table 9-18]

Subsystem	Design Temperature (°F)
Switchgear Room	104
EDG Rooms	120
AFW Pump Room	90
Main steam penetration area	160
Waste processing	110
Fuel handling area	110
ECCS Pump Room	110

The internal environment for the Auxiliary Building H&V System consists of outside air or of air drawn from ventilated areas. No design requirements exist for maintaining humidity below a specified value in the Auxiliary Building. However, the maximum normal relative humidity inside the Auxiliary Building areas is 70%. [Reference 15] Outdoor air could reach a relative humidity of up to 100%. All of these components are located in ventilated areas indoors and, therefore, not exposed to the outside weather or sun.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, surface deposits, designed crevices for attaching thermal sleeves to safe-ends, and integral weld backing rings or back-up bars. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits in many cases, as well as leading to stress corrosion cracking. [Reference 2, Attachments 6 and 7]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. General corrosion requires an aggressive environment and materials susceptible to that environment. The consequences of the damage are loss of load carrying cross-sectional area. [Reference 2, Attachments 6 and 7]

Pitting is another form of localized attack with greater corrosion rates at some locations than at others. Pitting can be very insidious and destructive, with sudden failures in high pressure applications (especially in tubes) occurring by perforation. This form of corrosion essentially produces holes of varying depth to diameter ratios in the steel. Deep pitting is more common with passive metals, such as austenitic stainless steels, than with non passive metals. Pits are generally elongated in the direction of gravity. In many cases, erosion corrosion, fretting corrosion, and crevice corrosion can also lead to pitting. [Reference 2, Attachments 6 and 7]

For Group 1 components, there are two possible effects from long-term exposure to the moist environment; a uniform corrosion of the exposed steel surfaces causing material thinning, and localized attack resulting in pits and cracks. Those items that are painted or galvanized are protected from the effects of corrosion; however, where the coating is damaged, the corrosion may take place. The most likely locations for corrosion is in crevices at duct joints and between support angles and sheet metal. These corrosion ARDMs are not plausible for the registers constructed of aluminum because that material is resistant to corrosion in this mild environment. If corrosion were left unmanaged, it could eventually result in loss of the pressure-retaining capability under CLB design loading conditions. [Reference 2, Attachment 6]

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Methods to Manage Aging

Mitigation: Since there are no design features for control of humidity, the only feasible method of preventing exposure of these components to a corrosive environment is to apply a protective coating to them. Those subcomponents without a protective coating, or where the coating has degraded, will potentially be exposed to moisture from condensation. The subcomponents constructed of carbon steel materials could be replaced with subcomponents constructed of more corrosion resistant materials. [Reference 2, Attachment 8]

Discovery: The effects of corrosion (crevice corrosion, general corrosion, and pitting) on Group 1 components can be discovered and monitored through non-destructive examination techniques, such as visual inspections or pressure tests. [Reference 2, Attachment 8] Representative samples of susceptible locations can be used to assess the need for additional inspections at less susceptible locations.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Aging Management Program(s)

Mitigation: Maintaining the protective coatings, as discussed below in Discovery, will help to mitigate corrosion of these components. No other mitigation techniques are deemed necessary at this time, so there are no mitigation programs credited for managing corrosion of Group 1 components.

Discovery: For Group 1 components, crevice corrosion, general corrosion, and pitting can be readily detected through visual examination. Additionally, degraded protective coatings, which help mitigate corrosion, can also be visually detected so that corrective actions can be taken to restore the coatings. As such, an inspection program can provide the assurance needed to conclude that the effects of plausible aging are being effectively managed for the period of extended operation. Routine system walkdowns would discover corrosion of the external surfaces of the Group 1 components. To assure that corrosion is discovered if it exists on the internal surfaces of these components, they will be included in a new ARDI Program to accomplish the necessary inspections. [Reference 2, Attachment 8]

System Walkdowns

Calvert Cliffs Administrative Procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of general corrosion, and conditions that could allow corrosion to occur (e.g. degraded paint), of the Auxiliary Building H&V System by performance of visual inspections during plant walkdowns. The purpose of the procedure is to provide direction for the performance of structure and system walkdowns and for the documentation of the walkdown results. [Reference 16, Sections 1.1 and 1.2]

In accordance with MN-1-319, personnel with assigned responsibility for specific structures and systems perform periodic walkdowns. Walkdowns may also be performed as required for reasons such as material condition assessments; system reviews before, during, and after outages; start-up reviews (i.e., when a system is re-energized or placed in service); and as required for plant modifications. [Reference 16, Section 5.1]

One of the objectives of the walkdowns is to assess the condition of the CCNPP structures, systems, and components such that any degraded condition will be identified, documented, and corrective actions taken before the degradation proceeds to failure of the structures, systems, and components to perform their intended functions. [Reference 16, Sections 5.1.C, 5.2.A.1, and 5.2.A.5] Conditions adverse to quality are documented and resolved by the Calvert Cliffs Corrective Actions Program. The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed.

The procedure provides guidance for specific types of degradation or conditions to inspect for when performing the walkdowns. Inspection items related to aging management include the following: [Reference 16, Section 5.2 and Attachments 1 through 13]

- Items related to specific ARDMs such as corrosion or vibration;
- Effects that may have been caused by ARDMs such as damaged supports; concrete degradation, anchor bolt degradation, or leakage of fluids; and
- Conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, or inadequate support of components (e.g., missing, detached , or loose fasteners and clamps).

The walkdowns promote familiarity of the systems by the responsible personnel and provides extended attention to plant material condition beyond that afforded by Operations and Maintenance alone. The procedure has been improved over time, based on past experience, to provide guidance on specific activities to be included in the scope of the walkdowns.

The corrective actions taken as a result of system walkdowns will ensure that the Group 1 duct and heat exchangers remain capable of performing their passive intended function under all CLB conditions.

Age-Related Degradation Inspection Program

To monitor the effects of corrosion for internal surfaces of Group 1 components, they will be included within a new plant program to accomplish the needed inspections. This program is considered an Age-Related Degradation Inspection (ARDI) Program as defined in the CCNPP IPA Methodology presented in Section 2.0 of the BGE LRA.

The elements of the ARDI program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of unacceptable examination findings, including consideration of all design loadings required by the current licensing basis (CLB), and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

Corrective actions will be taken, as necessary, in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing the system pressure boundary integrity function under all CLB conditions.

Group 1 (crevice corrosion, general corrosion, and pitting for duct and heat exchangers) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to crevice corrosion, general corrosion, and pitting of duct and heat exchangers:

- The Group 1 components provide system pressure-retaining boundary and their integrity must be maintained under all CLB conditions.
- Crevice corrosion, general corrosion, and pitting are plausible for the components, and result in material loss which, if left unmanaged, can lead to loss of pressure-retaining boundary integrity.
- Existing visual inspections will continue to be performed in accordance with modified Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of degraded paint or galvanized surfaces, of external corrosion, or of internal corrosion that resulted in holes in the duct or cooler housing would be detected during these walkdowns. If unsatisfactory conditions are detected, corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- To provide the needed inspection for the internal surfaces of Group 1 components, they will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant corrosion is discovered.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, and pitting on Group 1 components will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Materials and Environment

The Auxiliary Building H&V System galvanized carbon steel ducting was installed with flexible collars in connections between fans and ducts or casings to prevent excessive movements of long ducts. These flexible collars are constructed of elastomers and are installed with sufficient slack to prevent transmission of vibration. Collars are secured to fans and ducts with galvanized steel bars fastened with bolts for an air-tight construction. Some of the Auxiliary Building H&V System dampers are required to maintain system pressure boundary while in the closed position, and they are provided with compressible seals for leak tightness. These seals are constructed of neoprene material, which is an elastomer. [Reference 2, Attachment 4s; Reference 11]

The internal and external environments for the Auxiliary Building H&V System components are discussed above in the Materials and Environment Section for Group 1.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Mechanism Effects

An elastomer is a material that can be stretched to significantly greater than original length and, upon release of the stress, will return with force to approximately its original length. When an elastomer ages, there are three mechanism primarily involved:

- Scission - The process of breaking molecular bonds, typically due to ozone attack, UV light, or radiation;
- Crosslinking - The process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Natural aging tests indicate that where there is a significant property change in a elastomer, it appears to occurs within the first five to ten years after initial formulation/curing. Measurable properties that change include hardness, modulus, elongation, tensile strength, and compression strength. Elastomers generally harden as they age making sealing more difficult. [Reference 2, Attachment 7s]

Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard, abrasive particles (abrasive wear) or fluid stream (erosion), and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting). Motions may be linear, circular, or vibratory in inert or corrosive environments. Fretting is a wear phenomenon that occurs between tight-fitting surfaces subjected to a cyclic, relative motion of extremely small amplitude. Common sites for fretting are in joints that are bolted, keyed, pinned, press fit or riveted, in oscillating bearings, couplings, spindles, and seals; in press fits on shafts; and in universal joints. [Reference 2, Attachment 7s]

Elastomer degradation and wear are plausible for the flexible collars since the elastomers will degrade at the joints in the HVAC equipment due to relative motion between vibrating equipment, pressure variations and turbulence, and exposure to temperature changes and oxygen. These stressors will result in eventual tearing of the boot. Elastomer degradation and wear are plausible for damper seals because the neoprene will degrade due to relative motion between the blade and sleeve during damper operation and exposure to temperature changes and oxygen. These stressors will result in eventual breakdown of the seal. [Reference 2, Attachment 6s] If left unmanaged, elastomer degradation and wear could eventually result in the loss of pressure boundary integrity of the duct flexible collars and damper seals under CLB design loading conditions.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Methods to Manage Aging

Mitigation: Elastomer degradation can be mitigated by utilizing materials that are less susceptible to heat and oxygen. Wear can be mitigated by minimizing operation of the dampers to slow degradation of the seating surfaces, which leads to a loss of leak tightness. [Reference 2, Attachment 7s]

Discovery: Periodic visual inspections can be performed for the Group 2 equipment to detect the effects of elastomer degradation and wear. Degradation of the flexible collars can be detected through periodic system walkdowns because the collars are readily accessible. Degradation of damper seals can be detected through continued inspections and walkdowns. If significant degradation is discovered, the flexible collars or damper seals can be repaired or replaced as appropriate. [Reference 2, Attachment 8]

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Aging Management Program(s)

Mitigation: The system was designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators such as the flexible collars. Changes to materials or to system operating practices are not deemed necessary to mitigate the effects of these ARDMs. Implementing the discovery methods discussed below are adequate methods to manage these ARDMs. Since there are no additional methods beyond these design features for mitigating elastomer degradation and wear, there are no programs credited with mitigating the aging effects due to these ARDMs. [Reference 2, Attachment 6s and 8]

Discovery:

Routine system walkdowns would discover elastomer degradation and wear of the duct flexible collars and possibly of the damper seals. To assure that degradation of the damper seals is not threatening the capability of the dampers to provide the pressure boundary function they will be included in a new ARDI Program.

System Walkdowns

Procedure MN-1-319 provides for discovery of the effects of elastomer degradation and wear by providing for system walkdowns that include visual inspections, reporting the walkdown results, and initiating corrective action. Under this program, inspection items typically related to aging management include identifying poor housekeeping conditions (such as degraded paint), and identifying system and equipment stress or abuse (such as excessive vibrations, bent or broken component supports, etc.). Signs of cracking or tearing of duct flexible collars would be detected during these walkdowns. In some cases, these walkdowns can detect degradation in the dampers, such as if a non-operating fan is rotating backward due to a leaking damper. All the accessible external surfaces of the subject equipment are monitored and conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 16] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion on Aging Management Programs for Group 1 for a detailed description of procedure MN-1-319.

ARDI Program

The system walkdowns can identify degradation evident externally from the components, which is adequate for the duct flexible collars and, in some cases, the damper seals. An inspection of the internals of the dampers would provide additional assurance that the effects of elastomer degradation and wear are being adequately managed. This inspection will be accomplished as part of an ARDI Program as defined in the CCNPP IPA Methodology presented in Section 2.0. Refer to the Group 1 discussion on aging management programs for a detailed discussion of the ARDI Program.

Corrective actions will be taken in accordance with the CCNPP Corrective Actions Program and will ensure that the components will remain capable of performing their pressure boundary integrity function under all CLB conditions.

Group 2 (elastomer degradation and wear for non-metallic duct and damper parts) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to elastomer degradation and wear for duct flexible collars and damper seals:

- Auxiliary Building H&V System ducts and dampers provide system pressure-retaining boundary and their integrity must be maintained under CLB design conditions.
- Elastomer degradation and wear are plausible for the flexible collars due to the relative motion between vibrating equipment, pressure variations, and turbulence, and exposure to temperature changes and oxygen. Elastomer degradation and wear are plausible for the damper seals due to relative motion between the blade and sleeve during damper operation and exposure to temperature changes and oxygen.
- If left unmanaged, elastomer degradation and wear can result in material loss, tearing, or cracking, which could lead to loss of pressure-retaining boundary integrity.
- Existing visual inspections will continue to be performed in accordance with modified Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of cracking or tearing of duct collars would be detected during these walkdowns, as well as such conditions as identifying unusual noises, leaks, or vibration. If unsatisfactory conditions are detected, corrective actions are taken in accordance with the CCNPP Corrective Actions Program.
- To provide the needed internal inspection for the dampers, they will be included in the scope of an ARDI Program. Inspections will be performed, and appropriate corrective action will be taken if significant degradation of the damper seals is discovered.

Therefore, there is reasonable assurance that the effects of elastomer degradation and wear for duct flexible collars and damper seals will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

Group 3 (dynamic loading for fans) - Materials and Environment

Group 3 is comprised of fans because the rotating equipment can cause vibration that causes dynamic loading of the fasteners. Normal bearing wear and dirt buildup cause imbalances in the rotating parts of the fans, thereby creating vibrations. Flexible collars are installed on the fans to provide dynamic isolation for adjacent components, which minimizes the dynamic loading for those components. The fans have air for their internal and external environments. [Reference 2, Attachment 7]

Fan housings and fasteners for the ECCS Pump Room exhaust fans, AFW Pump Room supply fans, EDG Room supply fans, Switchgear Room supply fans, and fuel handling area exhaust fans are constructed of carbon steel. The SRW Heat Exchanger Room supply and exhaust fan housings and supports are constructed of aluminum and the fasteners of carbon steel. The fan blades and motors do not perform a passive intended function. Therefore, they are not subject to AMR. [Reference 2, Attachment 4s]

Group 3 (dynamic loading for fans) - Aging Mechanism Effects

Dynamic loadings (vibrations) are created at blowers by rotating parts with imbalances due to dirt buildup and normal bearing wear. There is a history of loosened mechanical fasteners due to vibration in fans at CCNPP. This mechanism is plausible for the fans, but is not considered plausible for adjacent HVAC equipment due to the dynamic isolation provided by flexible collars. If dynamic loading was left unmanaged, it could eventually result in the loss of pressure boundary integrity of the Auxiliary Building H&V fans under CLB design loading conditions. [Reference 2, Attachments 5 and 6]

Group 3 (dynamic loading for fans) - Methods to Manage Aging

Mitigation: Dynamic loading can be mitigated by minimizing the mechanical loading due to vibration. The system is designed to minimize vibration by using equipment support isolators and equipment-to-duct isolators, such as flexible collars. Visual inspections during system walkdowns would provide for detection of vibration so that corrective actions could be taken to minimize vibration and, thereby, mitigate the effects of dynamic loading. [Reference 2, Attachment 8]

Discovery : The effects of dynamic loading, e.g., loosened fasteners, can be detected through visual inspections. Periodic visual inspections during system walkdowns would provide for detection of the effects of dynamic loading, as well as vibration problems that can cause this ARDM to occur. [Reference 2, Attachment 8]

Group 3 (dynamic loading for fans) - Aging Management Program(s)

Mitigation: System walkdowns provide for periodic visual inspections of the external surfaces of Auxiliary Building H&V System components. During these walkdowns any vibration problems would be detected so that corrective actions can be taken to minimize the vibration. [Reference 2, Attachment 8] Refer to the discussions below in Discovery for a description of the system walkdowns.

Discovery: Routine inspections are performed on system components in accordance with Administrative Procedure MN-1-319. System walkdowns are credited for discovery of the effects of dynamic loading, as well as abnormal or excessive vibration, which can cause dynamic loading to occur. Procedure MN-1-319 requires routine system walkdowns that include visual inspections, reporting the walkdown results, and initiating corrective action. Under this procedure, inspection items typically related to aging management include identifying unusual noises and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, etc. Conditions identified as adverse to quality are corrected in accordance with the CCNPP Corrective Actions Program. [Reference 16] The existing procedure will be modified to include specific inspection items with respect to discovery of these ARDMs to help ensure they are being adequately managed. Refer to the discussion above in Group 1 under Aging Management Programs for a detailed discussion of procedure MN-1-319.

Group 3 (dynamic loading for fans) - Demonstration of Aging Management

Based on the factors presented above, the following conclusions can be reached with respect to dynamic loading for all Auxiliary Building H&V fans:

- Auxiliary Building H&V System fans provide the system pressure-retaining boundary and their integrity must be maintained under CLB design conditions.
- Dynamic loading is a plausible ARDM for the fans due to excessive vibration resulting from fan operation.
- If left unmanaged, dynamic loading can result in loosened fasteners, which could lead to loss of pressure-retaining boundary integrity.
- Existing visual inspections will continue to be performed in accordance with modified CCNPP Administrative Procedure MN-1-319 to help ensure that these ARDMs are being adequately managed. Signs of loosened fasteners would be detected during these walkdowns, as well as such conditions as identifying unusual noises or vibration, so that corrective actions can be taken to mitigate this ARDM.

Therefore, there is reasonable assurance that the effects of dynamic loading for fans will be managed in such a way as to maintain the components' pressure boundary integrity, consistent with the CLB, during the period of extended operation.

5.11A.3 Conclusion

The programs discussed for the Auxiliary Building H&V System are listed in Table 5.11A-3. These programs are (and will be for new programs) administratively controlled by a formal review and approval process. As has been demonstrated in the above section, these programs will manage the aging mechanisms and their effects such that the intended functions of the components of the Auxiliary Building H&V System will be maintained, consistent with the CLB, during the period of extended operation.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

Table 5.11A-3

LIST OF AGING MANAGEMENT PROGRAMS FOR THE AUXILIARY BUILDING H&V SYSTEM

	Program	Credited As
Modified	CCNPP System Walkdowns Administrative Procedure MN-1-319, "Structure and System Walkdowns" Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	• Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the external surfaces of duct and heat exchangers (Group 1) • Discovery and management of the effects of elastomer degradation and wear for the duct flexible collars (Group 2) • Mitigation of vibration and discovery and management of the effects of dynamic loading for the fans (Group 3)
New	ARDI Program	• Discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the internal surfaces of duct and heat exchangers (Group 1) • Discovery and management of the effects of elastomer degradation and wear for the surfaces of damper seals (Group 2)

5.11A.3 References

1. "CCNPP Updated Final Safety Analysis Report," Revision 20
2. "CCNPP Auxiliary Building and Radwaste H&V System Aging Management Review Report," Revision 1, March 21, 1997
3. CCNPP Drawing No. 60722SH0001, "Auxiliary Building Ventilation Systems," Revision 40, January 16, 1997
4. CCNPP Drawing No. 60722SH0002, "Auxiliary Building Ventilation Systems," Revision 36, December 2, 1996
5. CCNPP Drawing No. 60722SH0003, "Auxiliary Building Ventilation Systems," Revision 3, August 29, 1996
6. CCNPP Drawing No. 60723SH0001, "Ventilation Systems: Containment, Turbine, and Penetration Rooms," Revision 38, July 12, 1996
7. CCNPP Drawing No. 60625SH0015, Service Water Heat Exchanger Room Ventilation," Revision 2, November 21, 1990
8. CCNPP Drawing No. 60708SH0002, "Circulating Saltwater Cooling System," Revision 78, November 28, 1996
9. CCNPP Report, "Component Level Screening Results for the Auxiliary Building and Radwaste H&V System, System No. 032," Revision 2, July 10, 1996
10. CCNPP Engineering Standard ES-011, "System, Structure, and Component (SSC) Evaluation," Revision 4, August 27, 1996
11. CCNPP Specification No. 6750-M-196, "Specification for Heating, Ventilating, and Air Conditioning Ducts," Revision 4, June 14, 1974
12. Letter from Mr. L. B. Russell (BGE) to Mr. B. H. Grier (NRC), dated July 18, 1980, "Thirty-day Report for Licensee Event Report 80-29/3L"
13. CCNPP Preventive Maintenance Checklist MPM09021, "Auxiliary Building H&V Damper Inspection"
14. CCNPP Report, "Component Pre-Evaluation for the Auxiliary Building and Radwaste H&V System (032)," Revision 1, February 14, 1997
15. CCNPP Engineering Standard ES-014, "Summary of Ambient Environmental Service Conditions", Revision 0, November 8, 1995
16. CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns," Revision 0, September 16, 1997

ATTACHMENT (3)

APPENDIX A - TECHNICAL INFORMATION

5.16 - SALTWATER SYSTEM

5.16 Saltwater System

This is a section of the Baltimore Gas and Electric Company (BGE) License Renewal Application (LRA), addressing the Saltwater (SW) System. The SW System was evaluated in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) Integrated Plant Assessment (IPA) Methodology described in Section 2.0 of the BGE LRA. These sections are prepared independently and will, collectively, comprise the entire LRA.

5.16.1 Scoping

System level scoping describes conceptual boundaries for plant systems and structures, develops screening tools which capture the 10 CFR 54.4(a) scoping criteria, and then applies the tools to identify systems and structures within the scope of license renewal. Component level scoping describes the components within the boundaries of those systems and structures that contribute to the intended functions. Scoping to determine components subject to Aging Management Review (AMR) begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, or subject to AMR either in this report or another report.

Section 5.16.1.1 presents the results of the system level scoping, 5.16.1.2 the results of the component level scoping, and 5.16.1.3 the results of scoping to determine components subject to an AMR.

5.16.1.1 System Level Scoping

This section begins with a description of the system that includes the boundaries of the system as it was scoped. The intended functions of the system are listed and are used to define what portions of the system are within the scope of license renewal.

<u>System Description/ Conceptual Boundaries</u>

The SW System is a safety-related system. Each CCNPP unit has three SW pumps that provide the driving head to move SW from the intake structure, through the system, and back to the circulating water discharge conduit. A simplified diagram of the system is provided in Figure 5.16-1. The system is designed such that each pump has sufficient head and capacity to provide cooling water for the Service Water (SRW) System, Component Cooling (CC) System, and Emergency Core Cooling System (ECCS) pump room air coolers, as required by 10 CFR Part 50, Appendix A. [Reference 1, Section 1.1.1; Reference 2]

The SW System in each unit consists of two subsystems. Each subsystem provides SW to a SRW heat exchanger, a CC heat exchanger, and an ECCS pump room air cooler in order to transfer heat from these heat exchangers and coolers to the Chesapeake Bay. Seal water for the circulating water pumps (which supply water to the main condensers) is supplied by both subsystems. [Reference 1, Section 1.1.1]

During normal operation, both subsystems in each unit are in operation with one pump running on each header and a third pump in standby. If needed, the standby pumps can be lined-up to either supply header in their respective units. The SW flow through the SRW and CC heat exchangers is throttled to provide sufficient cooling to the heat exchangers, while maintaining total subsystem flow below a maximum value. [Reference 1, Section 1.1.1]

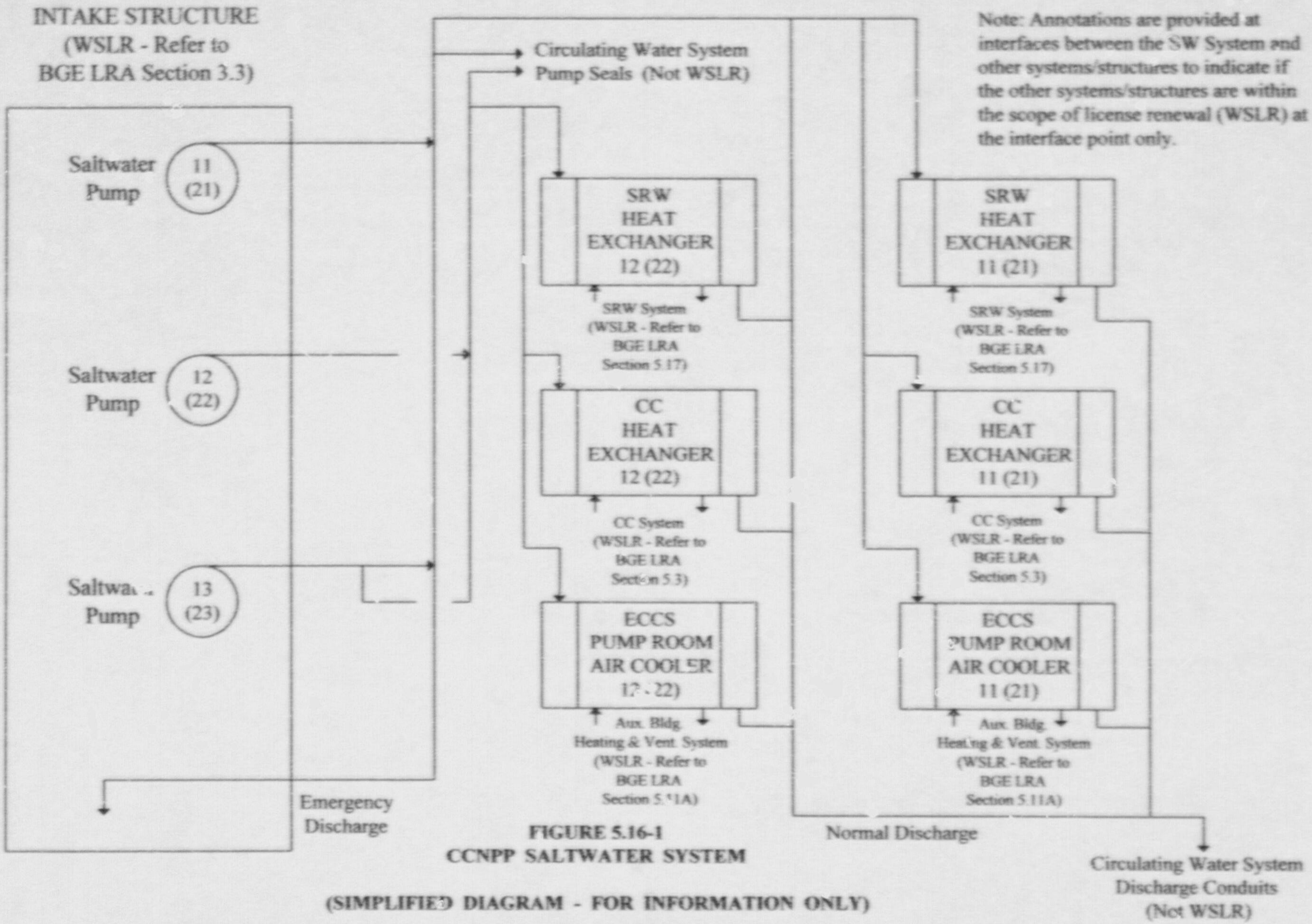

FIGURE 5.16-1
CCNPP SALTWATER SYSTEM

(SIMPLIFIED DIAGRAM - FOR INFORMATION ONLY)

Operation following a loss-of-coolant accident has two phases: before the Recirculation Actuation Signal (RAS) and after the RAS. One subsystem can satisfy the cooling requirements of both phases. [Reference 1, Section 1.1.1]

After a loss-of-coolant accident but before a RAS, each subsystem will cool an SRW heat exchanger and an ECCS pump room air cooler. Flow to the ECCS pump room air cooler is initiated only if required due to high room temperature. The minimum required SW flow is 16,830 gpm to each SRW heat exchanger, and 400 gpm to each ECCS pump room air cooler. There is no flow to the CC heat exchangers. System flow is not throttled. [Reference 1, Section 1.1.1; Reference 3]

When a RAS occurs, the minimum required flow to each SRW heat exchanger is reduced to 9,500 gpm, and each ECCS pump room air cooler remains at 400 gpm. Flow is restored to the CC heat exchangers at a minimum required amount of 5,500 gpm each. System flow is throttled for this phase. [Reference 1, Section 1.1.1]

In defining the scope of the SW System evaluation, an exception was made to the boundary convention. The SRW and CC heat exchangers are included in the scope of this evaluation even though heat exchangers are normally considered part of the systems they cool. This exception was made because age-related degradation is much more severe on the SW side of the heat exchangers. [Reference 1, Section 1.1.2]

Operating Experience:

Representative historical operating experience pertinent to aging is provided in this section and other appropriate sections to provide insight supporting the aging management demonstrations. This operating experience was obtained through key-word searches of BGE's electronic database of information on the CCNPP dockets, and through documented discussions with currently assigned cognizant CCNPP personnel.

During the 1984 CCNPP Unit 2 refueling outage, two through-wall holes occurred during work on the SW side of one CC heat exchanger channel head in preparation for coal tar epoxy application. The CC heat exchanger through-wall attack was attributed to graphitic corrosion. A visual examination was subsequently conducted on the operating Unit 1 CC and SRW heat exchanger channel heads. Two of the CC heat exchangers had three areas with apparent through-wall weepage. Unit 1 was then shut down and all CC and SRW heat exchangers were examined. Due to the size, location, and number of areas found below minimum wall on the channel heads, several repairs or channel head replacements were made. All CC and SRW heat exchanger channel heads were coated with coal tar epoxy to prevent future corrosion. These graphitic corrosion problems were the subject of NRC Information Notice No. 84-71. As shown in Table 5.16-4, the current design for these heat exchangers uses neoprene rubber linings in the channel heads rather than the coal tar epoxy coating used previously. [References 4 and 5]

The SW System has experienced through-wall pressure boundary failures of carbon steel aboveground piping lined with concrete, including occurrences in 1984 and 1991. The cause of the failures was due to failure of the concrete lining and subsequent corrosion of the bare metal exposed to SW. A modification has been performed to replace the aboveground concrete-lined piping with rubber-lined piping. [References 6 and 7]

In 1990, a pin hole leak was observed in the discharge piping of one of the Unit 1 SW pumps. The cause of the leak was localized corrosion of an inner weld connecting a slip-on flange to the pipe and localized corrosion of the pipe between welds. The corrosion occurred because of the failure of the grout lining that was applied during construction to protect field welds. Corrective actions included inspection of other flanges in the SW System. Grout lining deficiencies were found on other flanges and, in each case, the grout was removed and replaced with an epoxy-type lining. [References 8 and 9]

The SW side of the SRW heat exchangers has experienced erosion corrosion in the past. During the spring 1994 Unit 1 refueling outage, 140 plugged tubes were replaced in the No. 11 SRW heat exchanger. These tubes had previously been plugged due to leakage. During the replacement, it was discovered that there was severe tube wall thinning in the first three to four inches of the inlet end of the tubes. Tube damage was apparently caused by erosion corrosion on the tube side. Further inspection indicated that similar damage was widespread in both the No. 11 and 21 SRW heat exchangers. This problem was temporarily addressed by installing sleeves in the inlet end of the tubes. The existing heat exchangers also have experienced degraded thermal performance due to fouling. These problems have required frequent cleaning of the heat exchangers, which restricts operational flexibility. Due to the erosion corrosion and thermal performance problems, BGE plans to replace the existing tube and shell SRW heat exchangers with new plate and frame heat exchangers having increased thermal performance capability. The materials chosen for the new heat exchangers (Titanium for the plates and EPDM *[Ethylene Propylene Diene Monomer]* for the gaskets) and the method by which they will be assembled will provide deterrence to the erosion corrosion problem that damaged the existing heat exchangers. [Reference 3]

Nuclear Regulatory Commission Generic Letter 89-13 outlined concerns regarding the safe operation and maintenance of open-cycle cooling water systems. For CCNPP Units 1 and 2, the open-cycle cooling water system in the scope of Generic Letter 89-13 is the SW System. In response to Generic Letter 89-13, BGE committed to establishing a routine inspection and maintenance program for the SW piping and components to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade system performance. Specific actions completed by BGE are as follows: [Reference 10]

- Differential pressure across each SRW heat exchanger is monitored twice per shift. The SRW heat exchangers and the CC heat exchangers are bulleted periodically.
- The program for cleaning and inspecting the SRW, CC, and ECCS heat exchangers was established.
- The piping ultrasonic thickness inspection program was reviewed and revised.
- An underground piping inspection program was established.

System Interfaces:

The SW System interfaces with the following systems: [Reference 2; Reference 11, Section 9.5.2.3]

- SRW System;
- CC System;
- Auxiliary Building Heating and Ventilation System (ECCS pump room air coolers);

- Circulating Water System;
- Compressed Air System; and
- Engineered Safety Features Actuation System.

Interfaces in the major flow path are indicated on Figure 5.16-1.

System Scoping Results

The SW System is in scope for license renewal based on 10 CFR 54.4(a). The following intended functions of the SW System were determined based on the requirements of §54.4(a)(1) and (2) in accordance with the CCNPP IPA Methodology Section 4.1.1. [Reference 12, Table 1]

- Provide the vital auxiliary function of supplying cooling water to the CC and SRW Heat Exchangers and the ECCS Pump Room Air Coolers during design basis events;
- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To restrict flow to a specified value in support of a design basis event response.

The following intended functions of the SW System were determined based on the requirements of §54.4(a)(3): [Reference 12, Table 1]

- For environmental qualification (10 CFR 50.49) - To maintain functionality of electrical components as addressed by the Environmental Qualification Program;
- For fire protection (10 CFR 50.48) - To provide the ultimate heat sink for the SRW and CC Systems to ensure safe shutdown in the event of a postulated severe fire; and
- For post-accident monitoring - To provide information used to assess the environs and plant condition during and after an accident.

5.16.1.2 Component Level Scoping

Based on the intended functions listed above, the portion of the SW System that is within the scope of license renewal includes the components (electrical, mechanical, and instrumentation) and their supports along the system flowpath shown in Figure 5.16-1. These components include the SW pumps and motors, the SRW and CC heat exchangers, the ECCS pump room air coolers, the basket strainers located upstream of the ECCS pump room air coolers, air accumulators for control valves, and the associated piping, valves, instruments, and controls. [Reference 1, Section 1.1.2; Reference 2; Reference 12, Table 2]

A total of 40 device types within the SW System were designated as within the scope of license renewal because they have at least one intended function: These device types are listed in Table 5.16-1. [Reference 1, Table 2-1, Attachment 3s]

TABLE 5.16-1

SW SYSTEM DEVICE TYPES WITHIN THE SCOPE OF LICENSE RENEWAL

Device Code	Device Description	Device Code	Device Description
-JE2	Red Brass Piping	LY	Level Relay
-JG1	70-30 Copper-Nickel Piping	MA	4kV Motor
-LC2	Cast Iron or Carbon Steel Piping with Cement Mortar Lining	MOV	Motor-Operated Valve
-LJ1	Carbon Steel Piping with Neoprene Lining	NA	4kV Local Control Station
-MC6	Carbon Steel Piping with Saran or Neoprene Lining	PCV	Pressure Control Valve
-MC8	Carbon Steel Piping with Kynar Lining	PDI	Differential Pressure Indicator
ACC	Accumulator	PDIS	Differential Pressure Indicating Switch
BS	Basket Strainer	PI	Pressure Indicator
CKV	Check Valve	PS	Pressure Switch
COIL	Coil	PT	Pressure Transmitter
CV	Control Valve	PUMP	Pump/Driver Assembly
FO	Flow Orifice	RV	Relief Valve
FU	Fuse	RY	Relay
HIC	Hand Indicator Controller	SV	Solenoid Valve
HS	Hand Switch	TI	Temperature Indicator
HV	Hand Valve	TP	Temperature Test Point
HX	Heat Exchanger	TS	Temperature Switch
I/P	Current to Pneumatic Transducer	XJ	Expansion Joint
II	Ammeter	ZL	Position Indicating Lamp
JL	Power Indicating Lamp	ZS	Position Switch

In addition, some components within the scope of license renewal are common to many plant systems and perform the same passive functions regardless of system. These components are not included in the above table and are as follows:

- Structural supports for piping, cables and components;
- Electrical cabling; and
- Instrument lines (i.e., tubing and small bore piping), and the associated tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings.

5.16.1.3 Components Subject to AMR

This section describes the components within the SW System that are subject to AMR. It begins with a listing of passive intended functions and then dispositions the device types as either only associated with active functions, subject to replacement, evaluated in other system reports, evaluated in commodity reports, or remaining to be evaluated for aging management in this section.

Passive Intended Functions

In accordance with CCNPP IPA Methodology Section 5.1, the following SW System functions were determined to be passive: [Reference 1, Table 3-1]

- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain electrical continuity and/or provide protection of the electrical system; and
- To restrict flow to a specified value in support of a design basis event.

Device Types Subject to AMR

Of the 40 device types within the scope of license renewal shown in Table 5.16-1:

- Fourteen device types (Coil, Fuse, Hand Indicator Controller, Hand Switch, Ammeter, Power Indicating Lamp, Level Relay, 4 kV Motor, Motor Operated Valve, 4 kV Local Control Station, Relay, Temperature Switch, Position Indicating Lamp, Position Switch) only have active intended functions. [Reference 1, Table 3-2].
- One device type (Expansion Joints) is subject to periodic replacement. Some current/pneumatic transmitters and some solenoid valves are also subject to periodic replacement. [Reference 1, Table 3-2; Reference 13, Attachment 2]
- Five device types (Differential Pressure Indicator, Differential Pressure Indicating Switch, Pressure Switch, Pressure Indicator, Pressure Transmitter) are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. [Reference 1, Table 3-2]

The remaining 20 device types, listed in Table 5.16-2, are subject to AMR and are included in the scope of this report. Unless otherwise annotated, all components of each listed type are covered. [Reference 1, Table 3-2, Attachment 3s]

TABLE 5.16-2

SW SYSTEM DEVICE TYPES REQUIRING AMR

Device Code	Device Description	Device Code	Device Description
-JE2	Red Brass Piping	FO	Flow Orifice
-JG1	70-30 Copper-Nickel Piping	HV	Hand Valve*
-LC2	Cast Iron or Carbon Steel Piping with Cement Mortar Lining	HX	Heat Exchanger
-LJ1	Carbon Steel Piping with Neoprene Lining	I/P	Current to Pneumatic Transducer**
-MC6	Carbon Steel Piping with Saran or Neoprene Lining	PCV	Pressure Control Valve
-MC8	Carbon Steel Piping with Kynar Lining	PUMP	Pump/Driver Assembly
ACC	Accumulator	RV	Relief Valve
BS	Basket Strainer	SV	Solenoid Valve**
CKV	Check Valve	TI	Temperature Indicator
CV	Control Valve	TP	Temperature Test Point*

* Instrument line manual drain, equalization, and isolation valves and some temperature test points in the SW System that are subject to AMR are evaluated for the effects of aging in the Instrument Line Commodity Evaluation in Section 6.4 of BGE LRA. Instrument line manual root valves and the remaining temperature test points are evaluated in this report. [Reference 13, Attachment 4A]

** Some current/pneumatic transmitters and some solenoid valves are subject to periodic replacement. [Reference 13, Attachment 2]

Some components in the SW System are common to many plant systems and perform the same passive function regardless of system (i.e., structural supports, electrical cabling, and instrument lines as discussed in Section 5.16.1.2 above). Therefore, these components are not included in the 40 SW System device types discussed above, and they were evaluated as follows:

- Structural supports for piping, cables and components in the SW System that are subject to AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of the BGE LRA.
- Electrical cabling for components in the SW System that are subject to AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of the BGE LRA. This commodity evaluation completely addresses the SW System passive intended function, "To maintain electrical continuity and/or provide protection of the electrical system."
- Instrument lines (i.e., tubing and small bore piping), and the associated tubing supports, instrument valves (e.g., equalization, vent, drain, isolation), and fittings for components in the SW System that are subject to AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of the BGE LRA. This commodity evaluation addresses the SW System passive intended function, "To maintain the pressure boundary of the system (liquid and/or gas)" for instrument lines, and the associated supports, instrument valves, and fittings.

The only passive functions associated with the SW System that are not completely addressed by one of the commodity evaluations discussed above are:

- To maintain the pressure boundary of the system (liquid and/or gas); and
- To restrict flow to a specified value in support of a design basis event.

Therefore, only the two functions listed above for the 20 device types listed in Table 5.16-2 are addressed by the remainder of this section.

Baltimore Gas and Electric Company may elect to replace components for which the AMR identifies further analysis or examination is needed. In accordance with the License Renewal Rule, components subject to replacement based on qualified life or specified time period would not be subject to AMR.

5.16.2 Aging Management

The list of potential Age-Related Degradation Mechanisms (ARDMs) identified for the SW System components is given in Table 5.16-3, with plausible ARDMs identified by a check mark (✓) in the appropriate device type column. [Reference 1, Tables 4-1 and 4-2] A check mark indicates that the ARDM applies to at least one component for the device type listed. For efficiency in presenting the results of these evaluations in this report, ARDM/device type combinations are grouped together where there are similar characteristics and the discussion is applicable to all components within that group. Exceptions are noted where appropriate. Table 5.16-3 also identifies the group to which each ARDM/device type combination belongs. The following groups have been selected for the SW System:

Group 1 - Includes device types without internal lining subject to crevice corrosion, general corrosion, microbiologically-induced corrosion (MIC), and pitting.

Group 2 - Includes device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation.

Group 3 - Includes device types with air internal environments subject to general corrosion.

Group 4 - Includes the CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation.

Group 5 - Includes the ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 6 - Includes flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting.

TABLE 5.16-3

POTENTIAL AND PLAUSIBLE ARDMs FOR THE SW SYSTEM

Potential ARDMs	Device Types																			
	-JE	-JG	-LC	-LJ	-MC	ACC	BS	CKV	CV	FO	HV	HX	I/P	PCV	PUMP	RV	SV	TI	TP	Not Plausible for System
Cavitation Corrosion																				x
Corrosion Fatigue																				x
Crevice Corrosion	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(1)		✓(1)	✓(1)	
Dynamic Loading																				x
Elastomer Degradation				✓(2)	✓(2)				✓(2)		✓(2)	✓(4)								
Electrical Stressors																				x
Erosion Corrosion										✓(6)		✓(4)								
Fatigue																				x
Fouling																				x
Galvanic Corrosion			✓(2)	✓(2)	✓(2)		✓(2)	✓(2)	✓(2)		✓(2)				✓(2)					
General Corrosion		✓(1)	✓(2)	✓(2)	✓(2)	✓(3)	✓(2)		✓(2, 3)		✓(2, 3)	✓(4, 5)		✓(3)	✓(2)				✓(1)	
Hydrogen Damage																				x
Intergranular Attack																				x
MIC	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(1)		✓(1)	✓(1)	
Oxidation																				x
Particulate Wear Erosion			✓(2)							✓(6)										
Pitting	✓(1)	✓(1)	✓(2)	✓(2)	✓(2)		✓(2)	✓(1, 2)	✓(1, 2)	✓(6)	✓(1, 2)	✓(4, 5)			✓(2)	✓(1)		✓(1)	✓(1)	
Radiation Damage																				x
Saline Water Attack																				x
Selective Leaching																				x
Stress Corrosion Cracking																				x
Thermal Damage																				x
Thermal Embrittlement																				x
Wear																				x

✓ - indicates plausible ARDM determination

(#) - indicates the group(s) in which the ARDM/device type combination is evaluated

The following is a discussion of the aging management demonstration process for each group identified above. It is presented by group and includes a discussion of materials and environment, aging mechanism effects, methods to managing aging, aging management program(s), and aging management demonstration.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 1 applies to device types -JE, -JG, CKV, CV, HV, RV, TI, and TP that are subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 1 consists of piping, valves, temperature indicators, and temperature test points without any lining on their internal surfaces. [Reference 1, Attachment 1 for Group IDs JE-01, JG-01, CKV-01, CV-05, HV-01/02/03/06/07/10/11, RV-01, TI-01, TP-01]

All of the Group 1 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all of the Group 1 components is SW. [Reference 1, Attachment 3s]

Crevice corrosion, MIC, and pitting are plausible for each of the Group 1 device types. One or more of these ARDMs are plausible for the metal internal subcomponent parts that are exposed to the process fluid (i.e., SW). General corrosion is only plausible for Group 1 device types -JG and TP. Crevice corrosion, pitting, and/or general corrosion are plausible for metal external subcomponent parts (e.g., bolting) that may be exposed to leakage of the process fluid. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

The materials of the Group 1 components subject to plausible crevice corrosion, MIC, and pitting include: red brass, 70-30 copper-nickel, bronze, stainless steel, and monel. The Group 1 components subject to general corrosion include bolting constructed of low alloy steel and carbon steel. [Reference 1, Attachment 1, Attachment 4s and 5s]

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Mechanism Effects

Crevice corrosion is intense, localized corrosion within crevices or shielded areas. It is associated with a small volume of stagnant solution caused by holes, gasket surfaces, lap joints, crevices under bolt heads, and other mechanical joints that have a crevice geometry. The crevice must be wide enough to permit liquid entry and narrow enough to maintain stagnant conditions, typically a few thousandths of an inch or less. Crevice corrosion is closely related to pitting corrosion and can initiate pits (i.e., loss of material) in many cases. In an oxidizing environment, a crevice can set up a differential aeration cell to concentrate an acid solution within the crevice. Even in a reducing environment, alternate wetting and drying can concentrate aggressive ionic species to cause pitting and crevice corrosion. [Reference 1, Attachment 7s]

Pitting is a form of localized attack with greater corrosion rates at some locations than at others. This form of corrosion essentially produces holes of varying depth to diameter ratios in the metal. These pits are, in many cases, filled with oxide debris, especially in ferritic materials such as carbon steel. High concentrations of impurity anions such as chlorides and sulfates tend to concentrate in the oxygen depleted pit region, giving rise to a potentially concentrated aggressive solution in this zone. [Reference 1, Attachment 7s]

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. [Reference 1, Attachment 7s]

Microbiologically-induced corrosion is accelerated corrosion of materials resulting from surface microbiological activity. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria are most commonly associated with corrosion effects. This ARDM most often results in pitting, followed by excessive deposition of corrosion products. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. Any system that uses untreated water, or is buried, is particularly susceptible. Consequences range from leakage to excessive differential pressure and flow blockage. Essentially all systems and most commonly used materials are susceptible. Temperatures from about 50°F to 120°F are most conducive to MIC. [Reference 1, Attachment 7s]

Crevice corrosion and pitting are plausible for the internal metal surfaces of the Group 1 components since they are subjected to an aggressive SW environment. The components are susceptible to pitting and crevice corrosion due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid aggravates the pitting. [Reference 1, Attachment 6s]

General corrosion, crevice corrosion, and pitting are plausible for bolting of the Group 1 components. Although the bolting is not exposed to the process fluid, the potential for leakage of brackish water from the system onto the bolts exists. [Reference 1, Attachment 6s]

Microbiologically-induced corrosion is plausible for the internal metal surfaces of the Group 1 components due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. [Reference 1, Attachment 6s]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 1 components may not be able to perform their pressure boundary function under current licensing basis (CLB) conditions.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Methods to Manage Aging

Mitigation: Corrosion can be mitigated by design through the proper selection of materials. The occurrence of corrosion is expected to be limited, and is not likely to affect the intended function of components constructed of corrosion resistant materials such as brass, bronze, copper-nickel alloys, and stainless steel developed for SW service. Therefore, there are no additional mitigation measures deemed practical. The discovery activities discussed below are deemed adequate to manage aging for the Group 1 components. [Reference 1, Attachment 8]

Discovery: Visual inspections of representative components can be used to provide assurance that significant corrosion is not occurring for the Group 1 components. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the components will continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Management Program(s)

Mitigation: Since there are no mitigation measures deemed practical, there are no programs credited with mitigating aging for the Group 1 components.

Discovery: To verify that no significant crevice corrosion, general corrosion, MIC, or pitting is occurring on the Group 1 components, a new plant program will be developed to provide inspections of representative components. The program is considered an Age-Related Degradation Inspection (ARDI) Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are provided below. [Reference 1, Attachment 1 for Group IDs JE-01, JG-01, CKV-01, CV-05, HV-01/02/03/06/07/10/11, RV-01, TI-01, TP-01]

ARDI Program

The elements of the ARDI Program will include:

- Determination of the examination sample size based on plausible aging effects;
- Identification of inspection locations based on plausible aging effects and consequences of loss of component intended function;
- Determination of examination techniques (including acceptance criteria) that would be effective, considering the aging effects for which the component is examined;
- Methods for interpretation of examination results;
- Methods for resolution of adverse examination findings, including consideration of all design loadings required by the CLB and specification of required corrective actions; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program, QL-2, and will ensure that the Group 1 components remain capable of performing their passive intended functions under all CLB conditions.

Group 1 (Device types without internal lining subject to crevice corrosion, general corrosion, MIC, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 1 components:

- The Group 1 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.

- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the Group 1 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The ARDI Program will conduct inspections of representative components to discover the effects of crevice corrosion, general corrosion, MIC, and pitting, and will contain acceptance criteria that ensure corrective actions will be taken such that the components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting will be managed for the Group 1 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Materials and Environment

As shown in Table 5.16-3, Group 2 applies to device types -LC, -LJ, -MC, BS, CKV, CV, HV, and PUMP that are subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation.

Group 2 consists of piping, basket strainers, valves, and pumps with lining on their internal surfaces. [Reference 1, Attachment 1 for Group IDs LC-01, LJ-01, MC-01, BS-01, CKV-02, CV-03/04, HV-04/05, PUMP-01]

All of the Group 2 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all of the Group 2 components is SW. Most of the device type -LC piping is below ground (i.e., external environment is soil). The external surfaces of the buried piping is protected from the soil per standard industry practice with a multiple layer wrap and enamel coating. [Reference 1, Attachment 3s, Attachment 6 for Group ID LC-01]

The Group 2 components are lined to protect the underlying metal surfaces from the aggressive SW environment. The metal surfaces can potentially be subjected to the SW environment in locations where the lining has failed. The Group 2 lining materials include: cement mortar, neoprene, saran, kynar, Belzona (brand name), Tuboscope (brand name), Buna-N, natural rubber, hard rubber, polypropylene, and coal tar epoxy. The underlying metal materials include: cast iron, ductile iron, cast steel, and carbon steel. [Reference 1, Attachment 1]

Crevice corrosion, galvanic corrosion, MIC, and pitting are plausible for each of the Group 2 device types. One or more of these ARDMs are plausible for the metal internal subcomponent parts that could be exposed to the SW process fluid if the lining failed. Crevice corrosion, galvanic corrosion, MIC, and pitting are also plausible for the external surfaces of the buried piping that could be exposed to soil if the coating failed. Crevice corrosion, pitting, and general corrosion are plausible for metal external parts (e.g., bolting, cap screws) that may be exposed to leakage of the process fluid. The materials of the

Group 2 components subject to general corrosion include low alloy steel and carbon steel. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

Particulate wear erosion is only plausible for the Group 2 piping with cement mortar lining. Elastomer degradation is plausible for Group 2 components with lining constructed of neoprene, Buna-N, natural rubber, and hard rubber. [Reference 1, Attachment 4s, 5s, and 6s]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1.

Galvanic corrosion is an accelerated corrosion caused by dissimilar metals in contact in a conductive solution. Galvanic corrosion requires two dissimilar metals in physical or electrical contact, developed potential (material dependent), and conducting solution. [Reference 1, Attachment 7s]

Particulate wear erosion is loss of material caused by mechanical abrasion due to relative motion between the solution and material surface. This mechanism requires high velocity fluid and entrained particles, and turbulent flow regions, flow direction change, and/or impingement. Most materials are susceptible to varying degrees depending upon the severity of the environmental factors. [Reference 1, Attachment 7s]

Elastomers may degrade over time due to extended exposure to light, heat, oxygen, ozone, water, or radiation. When an elastomer ages, there are three mechanisms primarily involved: [Reference 1, Attachment 7s]

- Scission - The process of breaking of molecular bonds, typically due to ozone attack, ultraviolet light, or radiation;
- Crosslinking - The process of creating molecular bonds between adjacent long-chain molecules, typically due to oxygen attack, heat, or curing; and
- Compound ingredient evaporation, leaching, mutation, etc.

Scission and crosslinking have a major impact on physical property changes in elastomers. Scission results in increased elongation, decreased tensile strength, and decreased modulus. Crosslinking results in changes opposite to scission, i.e., decreased elongation, increased tensile strength, and increased modulus. For piping liner applications, elastomers are bonded to the inside surface of the pipe to prevent corrosive fluids from coming in contact with piping material. Piping liner debonding may occur if incorrect practices occurred during liner application. Piping liner debonding and degradation may result in failure of the elastomer material and allow the process fluid to come in contact with the underlying metal piping. [Reference 1, Attachment 7s]

As discussed in the Materials and Environment section above, the Group 2 components are lined to protect the underlying metal surfaces from the aggressive SW environment. The internal metal surfaces of the Group 2 components are susceptible to localized SW corrosive attack (i.e., crevice corrosion and pitting) in the event that there is lining failure. Galvanic corrosion (e.g., at an interface between a stainless steel thermowell and a carbon steel pipe) and MIC (e.g., due to bacteria in the SW) may also be a concern at locations of damaged lining. [Reference 1, Attachment 6s]

Crevice corrosion, galvanic corrosion, MIC, and pitting are plausible (although not likely) for the external surfaces of the buried piping (device type -LC) if the protective coating fails. However, SW inside the piping is a more aggressive environment than the homogeneous soil conditions that exist under the Turbine Building where the piping is located. In addition, the impressed current cathodic protection system and the site grounding grid provide some protection from galvanic and stray current corrosion on the external surfaces. Thus, corrosive attack is considered much more likely on the interior of the piping than on the exterior. [Reference 1, Attachment 6 for Group ID -LC-01]

General corrosion, crevice corrosion, and pitting are plausible for the bolting and cap screw subcomponents of the Group 2 components. Although these external subcomponents are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachment 6s]

Particulate wear erosion is plausible for Group 2 piping with cement mortar lining. The lining is susceptible to deterioration from chemical attack by SW on concrete hydration products, alkali-aggregate expansion, and abrasive wear (erosion) due to entrained particles in the SW. Cement mortar lining failure will result in exposure of the underlying metal piping surfaces to localized corrosive attack. [Reference 1, Attachment 6 for Group ID -LC-01]

Elastomer degradation is plausible for Group 2 components with lining constructed of neoprene, Buna-N, natural rubber, and hard rubber due to the combined effects of scission, crosslinking, and changes associated with compound ingredients. Significant degradation is not expected due to the service conditions. However, lining failure will result in exposure of the underlying metal component surfaces to localized corrosive attack. [Reference 1, Attachment 6s]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 2 components may not be able to perform their pressure boundary function under CLB conditions.

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Methods to Manage Aging

Mitigation: The effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for the Group 2 components are mitigated by design, by protecting the inner surfaces of the components with corrosion resistant linings. The lining provides physical separation of the susceptible metal surfaces from the aggressive SW environment.

The effects of crevice corrosion, galvanic corrosion, MIC, and pitting on the external surfaces of the buried piping are mitigated by design, by protecting the external surface with a protective coating. The coating provides physical separation of the susceptible metal piping from the soil. In addition, the impressed current cathodic protection system and the site grounding grid provide some protection from galvanic and stray current corrosion on the external surfaces. No other aging management methods are deemed necessary for managing galvanic corrosion on the external surfaces of the buried piping.

Since particulate wear erosion of the Group 2 cement mortar-lined piping is caused by mechanical abrasion due to entrained particles in the SW process flow, there are no reasonable methods to mitigate its effects. Similarly, since elastomer degradation of the Group 2 lined surfaces is caused by exposure of susceptible materials to environmental conditions that are not feasible to control (e.g., heat, oxygen, water, ozone), there are no reasonable methods to mitigate its effects. The discovery methods discussed below are deemed adequate to manage these ARDMs.

Discovery: The occurrence of corrosion is expected to be limited and not likely to affect the intended function of the Group 2 components so long as their corrosion-resistant linings remain intact. Visual inspections can be performed for signs of liner degradation and corrosion. If significant degradation is found, appropriate corrective actions can be taken to ensure that the components continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Aging Management Program(s)

Mitigation: For crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting, the mitigation measures are provided by design features (i.e., corrosion resistant lining). For particulate wear erosion and elastomer degradation, there are no reasonable mitigation measures. Therefore, there are no programs credited with mitigating aging for the Group 2 components.

Discovery: Most of the Group 2 components are subject to periodic inspection through existing plant preventive maintenance (PM) activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the components. The CCNPP PM Program and the specific maintenance activities are discussed in detail below. [Reference 1, Attachment 1 for Group IDs LC-01, LJ-01, BS-01, CKV-02, CV-03/04, HV-04, PUMP-01, Attachment 8]

Group 2 components that are not inspected by the PM Program will be included in a new plant program. The Group 2 components covered by this program include saran, kynar, or neoprene-lined carbon steel piping (device type -MC) and hand valves (device type HV) constructed of ductile iron or cast steel. These components are subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation. The program will inspect a representative sample of susceptible areas of the system for signs of liner degradation and corrosion. If any significant degradation is found, the program will provide appropriate corrective actions to ensure that the Group 2 components continue to perform their intended functions during the period of extended operation. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are described above in the Group 1 Aging Management Program section. [Reference 1, Attachment 1 for Group IDs MC-01, HV-05; Attachment 8, Attachment 10]

CCNPP PM Program

The CCNPP PM Program has been established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use, minimize equipment failure, and extend equipment and plant life. [Reference 14, Section 1.1]

The program is governed by CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," and covers all PM activities for nuclear power plant structures and equipment within the plant, including the SW System components within the scope of license renewal. References 15, 16, and 17 were used in the development of this program. [Reference 14, Section 2.1]

The PM Program includes periodic inspection of specific components through various maintenance activities. These activities provide an effective means to discover and manage the age-related degradation effects on these components. The program requires that an Issue Report be initiated according to CCNPP Procedure QL-2-100, "Issue Reporting and Assessment," for deficiencies noted during performance of PM tasks. Corrective actions are taken to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions. [Reference 1, Section 4.3; Reference 14, Section 5.2.B.1.f]

Specific responsibilities are assigned to BGE personnel for evaluating and upgrading the PM Program and for initiating program improvements based on system performance. Issue Reports are initiated according to CCNPP Procedure QL-2-100 to request changes to the program that could improve or correct plant reliability and performance. Changes to the PM Program that require Issue Reports included changes to the PM task scope, frequency, process changes, results from operating experience reviews, as well as other types of changes. [Reference 14, Sections 5.1.A and 5.4]

The PM Program is subject to periodic internal assessment. Internal audits are performed to ensure that activities and procedures established to implement the requirements of 10 CFR Part 50, Appendix B, comply with BGE's overall Quality Assurance Program. These audits provide a comprehensive independent verification and evaluation of quality-related activities and procedures. Audits of selected aspects of operational phase activities are performed with a frequency commensurate with their strength of performance and safety significance, and in such a manner as to assure that an audit of all safety-related functions is completed within a period of two years. An audit performed in 1997 of the CCNPP Maintenance Program (which includes the PM Program) concluded that the program is effectively implemented at CCNPP. No age-related degradation issues were identified. [Reference 18, Section 1B.18]

For the Group 2 components, the specific maintenance activities that manage the effects of aging are as follows:

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion and pitting of cement mortar-lined piping (device type -LC) is carried out by periodic inspection through Repetitive Tasks 10122066, 10122067, 10122068, 20122070, 20122071, 20122072. These repetitive tasks are performed during refueling outages to inspect the interior surface of the piping to verify that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1 and 8 for Group ID LC-01]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting and elastomer degradation of neoprene-lined piping (device type -LJ) is carried out by periodic inspection through Repetitive Tasks 10122063, 10122064, 10122065, 20122067, 20122068, 20122069. These repetitive tasks are performed during refueling outages to inspect the interior surface of the piping to verify that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1 and 8 for Group ID LJ-01]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for ECCS pump room air cooler basket strainers (device type BS) is carried out by periodic inspection and testing through PM Checklists MPM04004 and MPM04194. Checklist MPM04004 is performed every 12 weeks and MPM04194 is performed every 48 weeks. These checklists include steps to inspect for signs of leakage and corrosion and to verify the integrity of the liner. This activity detects degradation of the pressure boundary or bolting, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Section 4.2, Attachments 1 and 8 for Group ID BS-01]

- Management of crevice corrosion, galvanic corrosion, MIC, and pitting for SW pump discharge check valves (device type CKV) is carried out by periodic inspection and testing through PM Checklists MPM12200 and MPM12201. These PM checklists are performed on a six-year frequency to inspect the lining and body of the valves for degradation. These routine activities identify any degradation of the pressure boundary, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Section 4.3, Attachments 1 and 8 for Group ID CKV-02]

- Management of crevice corrosion, galvanic corrosion, MIC, pitting, and elastomer degradation of control valves (device type CV) associated with the ECCS pump room air coolers is carried out by periodic inspection and overhaul through Repetitive Tasks 10122096 through 10122102, and 20122100 through 20122106. These repetitive tasks are performed every six years. The occurrence of corrosion and liner degradation is expect d to be limited and is not likely to affect the intended function of the valves. Periodic valve overhaul verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachments 1, 3, and 8 for Group ID CV-03; Reference 12, Table 2]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation of control valves (device type CV) associated with the SRW heat exchangers is carried out by periodic inspection and testing through PM Checklists MPM01001 and MPM01181. These PM checklists are performed on a bi-annual frequency to inspect the lining and bodies of the valves for corrosion. These routine activities identify any degradation of the pressure boundary and corrective actions are taken to repair any deficiencies that are discovered. Checklist MPM01001 will be modified to add other SRW heat exchanger control valves that are not currently included in the checklist. [Reference 1, Attachments 1, 3, and 8 for Group ID CV-04, Attachment 10; Reference 12, Table 2]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation of the hand valves (device type HV) that provide the path to the circulating water discharge conduits is carried out by periodic inspection through Repetitive Tasks 10122068 and 20122072. These repetitive tasks are performed during refueling outages. Periodic inspection of .lves during piping inspection verifies that degradation is not occurring, and corrective actions are taken to repair any deficiencies discovered. [Reference 1, Attachments 1, 3, and 8 for Group ID HV-04; Reference 2; Reference 12, Table 2]

- Management of crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting for the SW pumps is carried out by pump inspection and overhaul through CCNPP Procedure PUMP-3, "Saltwater Pump Overhaul." These activities are performed as required based on pump performance trends or corrective action requirements. The procedure requires that the pump volute be inspected for signs of wear, erosion, corrosion, scratches, or cracks. Performance of this activity will identify degradation of the pump casings. Corrective actions are taken to repair any deficiencies discovered. [Reference 1, Section 4.3, Attachments 1 and 8 for Group ID PUMP-01; Reference 19, Page 29]

Group 2 (Device types with internal lining subject to crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 2 components:

- The Group 2 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation are plausible for the Group 2 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The PM Program conducts periodic inspections of specific components through performance of various maintenance activities that provide th[illegible]s to discover the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, [illegible]ulate wear erosion, pitting, and elastomer degradation for specific components. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.
- For Group 2 components that are not inspected by the PM Program, the ARDI Program will conduct inspections of representative components to discover the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation will be managed for the Group 2 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 3 (Device types with air internal environments subject to general corrosion) - Materials and Environment

As shown in Table 5.16-3, Group 3 applies to device types ACC, CV, HV, and PCV that are subject to general corrosion.

Group 3 consists of accumulators and valves that have air internal environments. [Reference 1, Attachment 1 for Group IDs ACC-01, CV-01, CV-02, HV-09, PCV-02]

All of the Group 3 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for all the Group 3 components is instrument air (IA). The IA supply is normally provided by the IA compressors and is very dry, filtered, oil-free air. Particle size, dew point, and oil hydrocarbons are controlled in accordance with industry standards. Occasionally, air that does not meet the same air quality standards may enter the IA System due to operation of the plant air compressors or the SW air compressors, which serve as backups to the IA compressors. Therefore, there is a possibility that moisture may enter the IA supply, although its effect is expected to be limited since the backup compressors are operated on a short-term basis An inspection performed on the piping immediately downstream of the SW air compressors, where the worst case of general corrosion is expected, revealed only very light surface rust on the inside of each piece. After more than 20 years in operation, approximately 60% of the pipe interior contained no rust and appeared similar to the inside of new pipe. Measurements showed negligible loss of wall thickness. [Reference 1, Attachment 3s, Attachment 8; Reference 11, Section 9.10; Reference 20, Attachment 8]

General corrosion is plausible for the internal carbon steel and iron subcomponent parts of the Group 3 components. [Reference 1, Attachment 1, Attachment 4s, 5s, and 6s]

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Mechanism Effects

General corrosion is the thinning (wastage) of a metal by chemical attack (dissolution) at the surface of the metal by an aggressive environment. The consequences of the damage are loss of load-carrying cross-sectional area. General corrosion requires an aggressive environment and materials susceptible to that environment. This ARDM is plausible for the Group 3 components because susceptible materials of construction are exposed to potentially moist air. However, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. [Reference 1, Attachment 7s, Attachment 8]

The expected effects of general corrosion on the internal carbon steel and iron subcomponent parts would be superficial rust speckles and a slight dusting of loose surface rust. [Reference 1, Attachment 6s]

This aging mechanism, if unmanaged, could eventually result in a loss of material such that the Group 3 components may not be able to perform their pressure boundary function under CLB conditions.

Group 3 (Device types with air internal environments subject to general corrosion) - Methods to Manage Aging

Mitigation: The effects of general corrosion for the Group 3 components can be mitigated by minimizing their exposure to an aggressive environment (i.e., minimizing moisture in the IA supply). As discussed above, the exposure of these components to moisture is expected to be minimal and short-term and is not expected to result in significant levels of degradation. Continued maintenance of the IA System air quality to industry standards will ensure minimal component degradation. [Reference 1, Attachments 6s, Attachment 8]

Discovery: There are no methods deemed necessary to discover general corrosion since the aging effects are expected to be minimal and can be mitigated by continued maintenance of the IA System air quality.

Group 3 (Device types with air internal environments subject to general corrosion) - Aging Management Program(s)

Mitigation: Moisture in the IA supply is minimized through PM checklists that are performed as part of the PM Program. The PM program details are described above in the Group 2 Aging Management Program section. For the Group 3 components, the specific maintenance activities that mitigate the effects of general corrosion are as follows:

- Calvert Cliffs initiated Preventive Maintenance Checklist IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality," following a review of industry operating experience. The industry operating experience recommends maintaining the air quality within the requirements of Instrument Society of America (ISA) Standard ISA-S-7.3, "Quality Standard for Instrument Air." Standard ISA-S-7.3 recommends limits for maximum particle size, dew point temperature, and oil content. Preventive Maintenance Checklist IPM 10000 (10001), checks instrument air quality at three locations in the IA System: at the dryer outlet, at the furthest point from the dryer, and at the approximate mid-point between the other two. The checklist is performed in accordance with CCNPP Repetitive Tasks 10191024 (20121022), "Check Unit 1(2) Instrument Air Quality at System Low Points." Measurements of dew point and particulate count are taken every 12 weeks. According to procedure, dew point data and particulate sample results are reviewed and trended. If it is determined the air quality is abnormal, corrective action is initiated to return the air quality to normal and the condition of the dependent load internals is investigated, as appropriate. This process ensures instrument air quality is maintained in accordance with industry standards for moisture (dew point). Operating experience relative to instrument air quality control has shown that the air normally provided is very dry and contains little particulate matter. [Reference 1, Section 4.3, Attachments 1 and 8; References 21 and 22]

Discovery: Since there are no methods deemed necessary to discover general corrosion, there are no programs credited with discovery of the aging effects due to this ARDM.

Group 3 (Device types with air internal environments subject to general corrosion) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 3 components subject to general corrosion:

- The Group 3 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- General corrosion is plausible for the Group 3 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- The PM Program minimizes moisture in the IA System through performance of various maintenance activities that provide the means to mitigate the effects of general corrosion. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of general corrosion will be managed for the Group 3 components such that they will be capable of performing their pressure boundary function, consistent with the CLB, during the period of extended operation.

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Materials and Environment

As shown in Table 5.16-3, Group 4 applies to device type HX that is subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation.

Group 4 consists of the CC and SRW heat exchangers. [Reference 1, Attachments 1 and 3 for Group ID HX-01]

All of the Group 4 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The subcomponent parts of the Group 4 heat exchangers, part materials, internal environment for each part, and plausible aging mechanisms are shown in the following table. [Reference 1, Attachments 4, 5, and 6 for Group ID HX-01]

TABLE 5.16-4

CC AND SRW HEAT EXCHANGERS

Subcomponent Part	Material	Environment	Plausible ARDMs
Shell	Carbon Steel	treated water	crevice corrosion general corrosion pitting
Channel Heads	Carbon Steel	SW	crevice corrosion MIC pitting
Tube Sheets	Aluminum-Bronze	treated water and SW	crevice corrosion MIC pitting
Tubes	Copper-Nickel	treated water and SW	crevice corrosion erosion corrosion MIC pitting
Channel and Channel Head Lining	Rubber/Neoprene	SW	elastomer degradation
Bolting	Carbon or Low Alloy Steel	N/A - external to process fluid	crevice corrosion general corrosion pitting

As discussed above in Section 5.16.1.1, the CCNPP SRW heat exchanger tubes have experienced erosion corrosion in the past. Baltimore Gas and Electric Company currently plans to replace the existing tube and shell SRW heat exchangers with new plate and frame heat exchangers that are more resistant to erosion corrosion. The SRW heat exchangers are scheduled to be replaced prior to the period of extended operation. [Reference 3]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1. Elastomer degradation is discussed in Group 2.

Erosion corrosion is an increased rate of attack on a metal because of the relative movement between a corrosive fluid and the metal surface. Mechanical wear or abrasion can be involved, characterized by grooves, gullies, waves, holes, or valleys on the metal surface. Erosion is a mechanical action of a fluid and/or particulate matter on a metal surface, without the influence of corrosion. The corrosive process is accelerated because the erosion removes the protective oxide film, which results in chemical attack or dissolution of the underlying metal. Inlet tube erosion corrosion occurs in heat exchangers, due to turbulence of flow from the heat exchanger head into the smaller tubes, within the first few inches of the tube. [Reference 1, Attachment 7]

Crevice corrosion and pitting are plausible for the shell because stagnant conditions may develop in idled portions of the system. [Reference 1, Attachments 5 and 6]

General corrosion is plausible for the shell because the material of construction is susceptible to this ARDM. [Reference 1, Attachments 5 and 6]

Crevice corrosion, MIC, and pitting are plausible for the channel heads if the channel head lining material (rubber/neoprene) fails (see elastomer degradation discussion below). The wall of the channel heads is susceptible to these ARDMs at the locations of damaged lining. [Reference 1, Attachments 5 and 6]

Crevice corrosion and pitting are plausible for the tube sheets and the tubes in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the tube sheets and the tubes due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Erosion corrosion is plausible for the inlet side of the heat exchanger tubes due to susceptible materials and flow conditions. It is also plausible based on plant operating experience as discussed above in Section 5.16.1.1.

Elastomer degradation is plausible for the channel and channel head lining due to the combined effects of scission, crosslinking, and changes associated with compound ingredients. Significant degradation is not expected due to the service conditions. However, lining failure will result in exposure of the underlying metal component surfaces to localized corrosive attack. [Reference 1, Attachments 5 and 6]

Crevice corrosion, general corrosion, and pitting are plausible for the bolting. Although these external components are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 4 components may not be able to perform their pressure boundary function under CLB conditions.

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Methods to Manage Aging

Mitigation: For the shell side of the heat exchangers, the effects of crevice corrosion, general corrosion, and pitting can be mitigated by minimizing the exposure of the shell to an aggressive environment. Maintaining CC System and SRW System chemistry conditions to minimize impurities will aid in the prevention of most corrosive mechanisms. [Reference 1, Attachment 8]

For the tube side of the heat exchanger (i.e., channel heads, tube sheets, tubes, channel and channel head lining, and bolting), the components are subject to a SW environment. Therefore, it is not feasible to control water chemistry. Corrosion of the channel heads is mitigated by the rubber/neoprene lining. However, some corrosion may occur if the lining fails. Some corrosion protection is also provided by sacrificial anodes that are installed in the channel heads. Therefore, discovery methods are deemed necessary to manage aging for these components.

Discovery: For the shell side of the heat exchangers, the occurrence of corrosion is expected to be limited and is not likely to affect the intended function of the heat exchangers. Visual inspections can be used to provide additional assurance that no significant degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

For the tube side of the heat exchangers, visual inspections and testing can determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Aging Management Program(s)

Mitigation: Calvert Cliffs Technical Procedure CP-206, "Specification and Surveillance for Component Cooling/Service Water Systems," is credited with managing the effects of crevice corrosion, general corrosion, and pitting for the shell side of the heat exchangers. The program provides for monitoring and maintaining CC System and SRW System chemistry to control the concentrations of oxygen, chlorides, other chemicals, and contaminants. The water is treated with hydrazine to minimize the amount of oxygen in the water, which aids in the prevention and control of most corrosive mechanisms. Continued maintenance of system water quality will ensure minimal piping or component degradation. [Reference 1, Attachment 8; Reference 23, Section 2.0]

Calvert Cliffs Technical Procedure CP-206 describes the surveillance and specifications for monitoring the CC System and SRW System fluid. CP-206 lists the parameters to monitor, the frequency of monitoring these parameters, and the target and action levels for the fluid parameters. The parameters monitored by CP-206 are pH, hydrazine, chloride, dissolved oxygen, dissolved copper, dissolved iron, suspended solids, gamma activity, and tritium activity (normally not radioactive systems). [Reference 23, Attachment 1]

These chemistry parameters are currently monitored on a frequency ranging from three times per week to once a month. All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter. Two of the parameters, pH and hydrazine, have action levels associated with them. If a target value or action level is not met, corrective actions are prescribed by the procedure, thereby ensuring timely response to chemical excursions. [Reference 23, Section 6.0.C, Attachment 1]

Operational experience related to CCNPP Technical Procedure CP-206 has shown no problems related to use of this procedure. In 1996, CP-206 was revised to include dissolved iron as a chemistry parameter. Dissolved iron was added to CP-206 to act as a method to discover any unusual corrosion of the CC System and SRW System components. [Reference 24]

Calvert Cliffs Technical Procedure CP-206 provides for a prompt review of CC System and SRW System chemistry parameters so that steps can be taken to return chemistry parameters to normal levels and, thus, minimize degradation due to corrosion mechanisms. [Reference 1, Attachment 8; Reference 23, Section 6.0.C]

Discovery: To verify that no significant crevice corrosion, general corrosion, or pitting is occurring for the shell side of the heat exchangers, a new plant program will be developed to provide inspections of a representative sample of susceptible areas for signs of degradation. The program is considered an ARDI Program as defined in the CCNPP IPA Methodology (reference Section 2.0 of the BGE LRA). The program details are discussed above in the Aging Management Program section for Group 1. [Reference 1, Attachment 8]

The tube side of the heat exchangers are subject to periodic inspection and testing through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the heat exchanger tube side subcomponent parts. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the tube side of the heat exchangers are as follows: [Reference 1, Attachment 8]

- Preventive Maintenance Checklists MPM00005 and MPM00006 are performed every two years to perform eddy current testing of the heat exchanger tubes. This routine activity will identify any degradation of the pressure boundary and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachment 8]
- Periodic cleaning and inspection of the tube side is carried out through Repetitive Tasks 10112052, 10112053, 10152023, 10152024, 20112006, 20112027, 20152020, and 20152021. These tasks inspect the channel heads, bolts, and sacrificial anodes, and clean the tubes every quarter (12 weeks). Periodic cleaning and inspection verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachment 8]

Group 4 (CC and SRW heat exchangers subject to crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 4 components:

- The Group 4 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation are plausible for the Group 4 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.

- For the shell side of the heat exchangers, Calvert Cliffs Technical Procedure CP-206 mitigates the effects of crevice corrosion, general corrosion, and pitting by maintaining CC System and SRW System chemistry conditions, and contains acceptance criteria that ensure timely correction of adverse chemistry parameters.
- For the shell side of the heat exchangers, the ARDI Program will conduct inspections of a representative sample of susceptible areas to discover signs of degradation, and will contain acceptance criteria that ensure corrective actions will be taken such that the heat exchangers remain capable of performing their passive intended functions under all CLB conditions.
- For the tube side of the heat exchangers, the PM Program conducts periodic inspection and testing through performance of various maintenance activities that provide the means to discover degradation. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation will be managed for the Group 4 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 5 applies to device type HX that are subject to crevice corrosion, general corrosion, MIC, and pitting.

Group 5 consists of the ECCS pump room air coolers. [Reference 1, Attachments 1 and 3 for Group ID HX-02]

All of the Group 5 components have the passive intended function to maintain pressure boundary integrity. [Reference 1, Attachment 1]

The internal environment for the heat exchangers is SW on the tube side and air on the shell side. [Reference 1, Attachment 3]

Crevice corrosion, MIC, and pitting are plausible for the heat exchanger channel heads and the tubes. The channel heads are constructed of cast iron and the tubes are copper-nickel. Crevice corrosion, general corrosion, and pitting are plausible for heat exchanger bolting which is constructed of carbon and low alloy steel. [Reference 1, Attachment 1, Attachment 4, 5, and 6]

There are no plausible ARDMs on the shell side of the ECCS pump room air coolers due to the air internal environment. [Reference 1, Attachments 3, 4, and 5]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, general corrosion, MIC, and pitting are as discussed above for Group 1.

The channel heads are lined with coal tar epoxy to protect the cast iron wall from the aggressive SW environment. Crevice corrosion, MIC, and pitting are plausible for the channel heads if the coal tar epoxy lining material fails. The wall of the channel heads is susceptible to these ARDMs at the locations of the damaged lining. [Reference 1, Attachments 5 and 6]

Crevice corrosion and pitting are plausible for the tubes in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the tubes due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Crevice corrosion, general corrosion, and pitting are plausible for the bolting. Although these external components are not exposed to the process fluid, the potential for leakage of SW from the system exists. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 5 components may not be able to perform their pressure boundary function under CLB conditions.

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Methods to Manage Aging

Mitigation: For the tube side of the heat exchanger (i.e., channel heads, tubes, and bolting), the components are subject to a SW environment. Therefore, it is not feasible to control water chemistry. Some corrosion protection is provided by sacrificial anodes that are installed in the channel heads. The discovery methods discussed below are deemed adequate to manage aging for these components.

Discovery: For the tube side of the heat exchangers, visual inspections and testing can be used to determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the heat exchangers continue to perform their intended function during the period of extended operation. [Reference 1, Attachment 8]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Aging Management Program(s)

Mitigation: Since there are no feasible mitigation methods, there are no programs credited with mitigating aging for the Group 5 components.

Discovery: The tube side of the heat exchangers are subject to periodic inspection and testing through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects on the heat exchanger tube side subcomponent parts. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the tube side of the heat exchangers are as follows: [Reference 1, Attachment 8]

- Preventive Maintenance Checklists MPM05000 and MPM05101, which are associated with the ECCS pump room air coolers, are performed every 24 weeks. Checklist MPM05000 replaces the sacrificial anodes, and Checklist MPM05101 inspects the channel heads and the tubes. Checklist MPM05101 presently calls for performance of a visual inspection of the tubes by using a light at one end of the heat exchanger while examining the tubes from the opposite end. Any debris found in the tubes is removed. Operating experience with this PM activity has indicated that there is little indication of age-related degradation of the tubes. In order to enhance the tube inspections, Checklist MPM05101 will be modified to visually inspect internal surfaces of a sample of the tubes at both the inlet and outlet ends of the heat exchanger. This maintenance activity will include appropriate surface cleaning of the tube surfaces that are inspected, and will include a requirement to inspect for roughness or irregularities that might indicate corrosion mechanisms are active. These routine activities will identify any degradation of the pressure boundary, and corrective actions will be taken to repair any deficiencies discovered. [Reference 1, Attachment 8]

Group 5 (ECCS pump room air coolers subject to crevice corrosion, general corrosion, MIC, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 5 components:

- The Group 5 components have the passive intended function to maintain pressure boundary integrity under CLB conditions.
- Crevice corrosion, general corrosion, MIC, and pitting are plausible for the Group 5 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary function under CLB conditions.
- For the tube side of the heat exchangers, the PM Program conducts periodic inspection and testing through performance of various maintenance activities that provide the means to discover and manage age-related degradation effects. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, general corrosion, MIC, and pitting will be managed for the Group 5 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Materials and Environment

As shown in Table 5.16-3, Group 6 applies to device type FO that is subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting.

Group 6 consists of flow orifices. [Reference 1, Attachment 1 for Group ID FO-01]

All of the Group 6 components have the passive intended functions to maintain pressure boundary integrity and to restrict flow to a specified value in support of a design basis event. [Reference 1, Attachment 1]

The internal environment for all of the Group 6 components is SW. [Reference 1, Attachment 3]

Crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting are plausible for the internal surfaces of the flow orifices. The flow orifices are constructed of stainless steel. [Reference 1, Attachment 4, 5, and 6]

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Aging Mechanism Effects

The aging mechanism effects for crevice corrosion, MIC, and pitting are as discussed above for Group 1. Erosion corrosion is discussed in Group 4. Particulate wear erosion is discussed in Group 2.

Crevice corrosion and pitting are plausible for the flow orifices in a SW environment. These components are susceptible to these ARDMs due to the presence of sulfates and chlorides. Dissolved oxygen and stagnant fluid will aggravate pitting. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Microbiologically-induced corrosion is plausible for the flow orifices due to the use of raw, untreated SW. Sulfate-reducing bacteria, sulfur oxidizers, and iron-oxidizing bacteria may be present in the process fluid. Stagnant or low flow areas are most susceptible, and sedimentation aggravates the problem. The materials of construction are resistant to most forms of corrosion and catastrophic failure of these components is not expected. [Reference 1, Attachments 5 and 6]

Erosion corrosion and particulate wear erosion are plausible for the flow orifices due to susceptible material of construction in an aggressive SW environment. These ARDMs may result in a loss of the inner diameter surface area that has the potential to adversely affect the intended flow restriction function. [Reference 1, Attachments 5 and 6]

These aging mechanisms, if unmanaged, could eventually result in a loss of material such that the Group 6 components may not be able to perform their pressure boundary and flow restriction functions under CLB conditions.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Methods to Manage Aging

Mitigation: The stainless steel material of construction for the flow orifices is designed to mitigate most forms of corrosion. Since the flow orifices are subject to a SW environment it is not feasible to control water chemistry. The discovery methods discussed below are deemed adequate to manage aging for these components.

Discovery: Visual inspections can be used to determine if any degradation is occurring. If any significant degradation is found, appropriate corrective actions can be taken to ensure that the flow orifices continue to perform their intended functions during the period of extended operation. [Reference 1, Attachment 8]

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Aging Management Program(s)

Mitigation: Since there are no feasible mitigation methods, there are no programs credited with mitigating aging for the Group 6 components.

Discovery: All except one of the Group 6 flow orifices are subject to periodic inspection through existing PM activities as part of the CCNPP PM Program. These activities provide an effective means to discover and manage the age-related degradation effects. The CCNPP PM Program details are discussed above in the Aging Management Program section for Group 2. The specific maintenance activities that manage the effects of aging for the flow orifices are as follows: [Reference 1, Attachment 8]

- Periodic inspection of the flow orifices is carried out through Repetitive Tasks 10122095 and 20122099. These tasks are performed every six years. Periodic inspection verifies that degradation is not occurring and corrective actions are taken to repair any deficiencies that are discovered. [Reference 1, Attachments 8 and 10]

As discussed above, one of the Group 6 flow orifices is not subject to periodic inspection through existing PM activities. This orifice (Unit 1 SRW heat exchanger SW emergency outlet orifice) was installed as part of a piping modification that was implemented in the 1993-1994 timeframe. Routine inspection of this orifice is not currently performed due to infrequent use of the flow path in which the orifice is installed. To verify that no significant age-related degradation is occurring for this orifice, it will be included in the ARDI Program inspections. The program details are discussed above in the Aging Management Program section for Group 1.

Group 6 (Flow orifices subject to crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting) - Demonstration of Aging Management

Based on the information presented above, the following conclusions can be reached with respect to the Group 6 components:

- The Group 6 components have the passive intended functions to maintain pressure boundary integrity and to restrict flow under CLB conditions.
- Crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting are plausible for the Group 6 components which, if unmanaged, could eventually result in loss of material such that the components may not be able to perform their pressure boundary and flow restriction functions under CLB conditions.
- The PM Program conducts periodic inspection through performance of various maintenance activities that provide the means to discover and manage age-related degradation effects. Corrective actions are taken to correct any deficiencies that are found to ensure that the affected components remain capable of performing their passive intended functions under all CLB conditions.
- For the orifice that is not inspected by the PM Program, the ARDI Program will conduct inspections to discover signs of degradation and will contain acceptance criteria that ensure corrective actions will be taken such that the orifice remains capable of performing its passive intended functions under all CLB conditions.

Therefore, there is reasonable assurance that the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting will be managed for the Group 6 components such that they will be capable of performing their intended functions, consistent with the CLB, during the period of extended operation.

5.16.3 Conclusion

The aging management programs discussed for the SW System are listed in the following table. These programs are administratively controlled by a formal review and approval process. As demonstrated above, these programs will manage the aging mechanisms and their effects such that the intended functions of the SW System components will be maintained during the period of extended operation consistent with the CLB under all design loading conditions.

The analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with QL-2, "Corrective Actions Program." QL-2 is pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to AMR.

TABLE 5.16-5

LIST OF AGING MANAGEMENT PROGRAMS FOR THE SW SYSTEM

	Program	Credited For
Existing	CCNPP Technical Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water System"	Mitigation of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the Group 4 heat exchangers.
Existing	CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"	Governs the specific maintenance activities shown below.
Modified	For Group 2: Repetitive tasks 10122063 through 10120268; 10122096 through 10122102; 20122067 through 20122072; and 20122100 through 20122106 Checklists MPM04004; MPM04194; MPM12200; MPM12201; MPM01001 (modification needed); and MPM01181 Procedure PUMP-03	Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation for the Group 2 components.
Existing	For Group 3: Checklists IPM10000 and IPM10001	Mitigation of the effects of general corrosion for the Group 3 components.
Existing	For Group 4: Repetitive tasks 10112052; 10112053; 10152023; 10152024; 20112006; 20112027; 20152020; and 20152021 Checklists MPM00005 and MPM00006	Discovery of the effects of crevice corrosion, erosion corrosion, general corrosion, MIC, pitting, and elastomer degradation for the tube side of the Group 4 heat exchangers.
Modified	For Group 5: Checklists MPM05000 and MPM05101 (modification needed)	Discovery of the effects of the crevice corrosion, general corrosion, MIC, and pitting for the tube side of the Group 5 heat exchangers.
Modified	For Group 6: Repetitive tasks 10122095 (modification needed) and 20122099	Discovery of the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting for the Group 6 components.

	Program	Credited For
New	ARDI Program	Discovery of the effects of crevice corrosion, general corrosion, MIC, and pitting for the Group 1 components. Discovery of the effects of crevice corrosion, galvanic corrosion, general corrosion, MIC, pitting, and elastomer degradation for the Group 2 components that are not inspected by the PM Program. Discovery of the effects of crevice corrosion, general corrosion, and pitting for the shell side of the Group 4 heat exchangers. Discovery of the effects of crevice corrosion, erosion corrosion, MIC, particulate wear erosion, and pitting for the Group 6 Unit 1 SRW overboard balancing orifice.

5.16.4 References

1. CCNPP "Aging Management Review Report for the Saltwater System," Revision 4, February 11, 1997
2. CCNPP Drawing 60708SH0002, "Circulating Salt Water Cooling System," Revision 78
3. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated May 16, 1997, "License Amendment Request: Service Water Heat Exchangers Replacement"
4. Letter from Mr. L. B. Russell (BGE) to NRC Document Control Desk, dated July 3, 1984, Transmittal of Licensee Event Report 84-05, Revision 1
5. NRC Information Notice 84-71, "Graphitic Corrosion of Cast Iron in Salt Water," September 6, 1984
6. Letter from Mr. E. C. Wenzinger (NRC) to Mr. A. E. Lundvall, Jr. (BGE), dated February 6, 1985, "NRC: RI Inspection 50-317/84-31, 50-318/84-31"
7. Letter From Mr. G. C. Creel (BGE) to NRC Document Control Desk, dated November 27, 1991, "Temporary Non-Code Repair of ASME Code Class 3 Piping"
8. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 4, 1990, CCNPP License Event Report LER 90-17, "Leaking Weld and Bio-Fouling in Saltwater System"
9. Letter from Mr. C. J. Cowgill (NRC) to Mr. G. C. Creel (BGE), dated July 12, 1990, "NRC Region I Resident Inspection Report Nos. 50-317/90-13 and 50-318/90-13 (June 3, 1990 to June 30, 1990)"
10. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 30, 1994, "Final Response to Generic Letter 89-13"
11. CCNPP Updated Final Safety Analysis Report, Revision 20
12. CCNPP Component Level Screening Results for the Salt Water Cooling System, Revision 3, July 15 1996
13. CCNPP "Component Pre-Evaluation for the Salt Water System," Revision 4, December 30, 1996
14. CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program," Revision 5, September 27, 1996
15. INPO 85-032, "Preventive Maintenance," December 1988
16. INPO 85-037, "Reliable Power Station Operation," October 1985
17. INPO Good Practice MA-319, "Preventive Maintenance Program Enhancement," December 1992
18. BGE "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48, March 28, 1997
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