U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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EXECUTIVE SUMMARY

This inspection concentrated on potential and plausible aging effects and the management of those aging effects. A number of systems and structures were chosen for detailed review by the NRC. Plausible aging effects were chosen for each system and structure and were examined in detail by the NRC team. The issues raised by the team were:

Calvert Cliffs Nuclear Power Plant (CCNPP) License Renewal Application (LRA), Section 6.2 - Electrical Commodities, stated thermal aging was plausible for the polyolefin rubber insulated wiring contained in the 480 volts alternating current motor control centers. Section 6.1 - Cables, states "Internal panel wiring at CCNPP is not exposed to high temperatures or high radiation levels; therefore, aging which could effect the functionality of the wiring during the period of extended operation is not considered plausible." These contradictory statements were corrected in a revision to the aging management review issued April 7, 1999, and reviewed by the NRC.

During the NRC walk down of containment, while traversing the auxiliary building roof, cracks were observed at buttresses three and four of Unit 1. The cracks originate at the cans covering the tendons and appear to migrate to the opposite side of the buttress. This cracking appears to be an observed aging effect the Baltimore Gas and Electric (BGE) LRA excludes. BGE will have an aging management program in place by September of 2001 under the accelerated implementation of American Society for Mechanical Engineers Boiler and Pressure Vessel Code (ASME) Section XI, Subsection IWL by NRC rule 50.55a (g) (6) (ii) (B) which will manage this aging effect; for which BGE can take credit. The NRC does not agree with BGE's conclusion that cracking of containment is not a plausible aging effect. BGE took up this matter and determined the Unit 2 buttresses do not contain cracking and is addressing the cracks identified by the NRC in Unit 1. Technical Problem Report TPR 99-036 was issued and reviewed by the NRC. BGE agreed corrosion of imbedded steel/rebar is plausible and will manage the effects thru the use of procedure MN1-319.

In 1994 BGE conducted a walk down inspection of the Auxiliary Building which revealed no structural damage due to settlement. Based on the results of this walk down BGE concluded in the Aging Management Report (AMR) for the Auxiliary Building, Revision 4, Dated May 29, 1998, Appendix J, paragraph 2.5, that settlement was not plausible. However in Issue Report Resolution Document (IRRD) IR1-024-713 dated 9/20/1996, addressing the operability of a support in the Auxiliary Building with a crack running diagonally under the support, the IRRD concluded "the diagonal cracking in this wall appears to be the result of settling of the Auxiliary Building." The conclusion of the IRRD does not support the conclusion arrived at in the AMR for the Auxiliary Building. This contradiction is being addressed in TPR 99-037 which was reviewed by the NRC team.

Leaching of the Salt Water System (SWS) is not considered plausible in the CCNPP LRA yet there is an extensive program at CCNPP to remediate the effect of this corrosion in the SWS. The conclusion that leaching is not plausible is inconsistent with the amount of leaching present and the program in place to take care of it. The NRC team does not agree with the conclusion. TPR 99-030 was generated to include leaching as a plausible aging effect and the report was reviewed by the NRC team.

Water hammer and thermal expansion loading are not, in of itself, an aging effect however a piping system repeatedly subjected to these events can accumulate aging effects such as bending of hangers and damage to the piping system. The CCNPP LRA concludes that water hammer and thermal expansion loading are not an aging effect because they are a function of design, procedure, and human performance. Attempts to control water hammer and thermal expansion loading by these three parameters has not been successful as evidenced by the repeated damage to the Unit 1 low pressure safety injection (LPSI) pipe support R-16. The LPSI pump discharge check valves are currently being replaced with fast acting check valves to control the amount of air being trapped in the LPSI common discharge header for the specific purpose of controlling water hammer. In a response to an NRC request for additional information (RAI) dated 11/19/98, BGE agreed that loading due to water hammer and thermal expansion effected threaded fasteners of component supports. Until water hammer and thermal loading is brought under control the NRC team believes water hammer and thermal expansion loading should be considered a plausible aging effects. Calvert agreed that aging effects associated with water hammer can be plausible and issued TPR 99-035 which was reviewed by the NRC team.

There are 13 electrical systems listed in table 5.10 - 1 of the BGE LRA with components that perform fire protection functions that are active. Those systems require no further evaluation because the remaining intended functions, that are passive, i.e. electrical continuity and component support, are addressed in other commodity evaluations. This section of the LRA lists, among the 13 electrical systems, the fire and smoke detection system as one requiring no further review because its passive function is addressed in a commodity evaluation. The aging management review, dated January 29, 1997, however concludes the fire and smoke detection system requires no further review because it has no pressure retention requirements. The conclusion submitted in the LRA for the fire and smoke detection system is not supported by the analysis developed in the AMR for the same system. The NRC reviewed TPR 99-031 which documented this matter by changing the AMR conclusion to correspond with the correct statement in the LRA.

The NRC reviewed procedures and programs credited with managing aging effects that are not able to completely manage the aging effect in all the locations for which they are being given credit. For example, in the AMR for the reactor coolant system (RCS) Group 064-CC-01 the Inservice Inspection (ISI) program is credited for managing primary water stress corrosion cracking (PWSCC), (not Stress Corrosion Cracking and Stress Corrosion Cracking Intergranular as written in the LRA) in the Pressurizer Sample Nozzle Neck when the component is excluded from ISI because it is smaller than the lower nominal diameter limit set in ASME. This specific issue was addressed in TPR 99-032 which removed the ISI program from aging management of the RCS system. Instead the aging effect will be managed by the existing Alloy 600 program which must be modified to include all the possible locations not currently interrogated by the program such as the Inconel® thermal sleeves in the Reactor Vessel nozzles. In addition BGE corrected the terminology used in the LRA and AMR from Stress Corrosion Cracking and Stress Corrosion Cracking (Intergranular) to the more generally accepted nomenclature of PWSCC. Another example of procedures not addressing an aging effect is the control room heating, ventilating, and air conditioning (HVAC) battery exhaust fan housing and fasteners where five plausible aging effects are identified for the two groups. Six preventive maintenance checklists were credited with discovery of these aging effects when they make no mention of the effect and will not, in their present form, discover the effect. This specific issue is addressed in TPR 97-129 by revisions of the maintenance checklists which will focus on the specific aging effects.

Another example of procedures not fully detecting the aging effect is the fire protection AMR. For fire protection system 013, the plausible aging effect of pressure boundary degradation was identified, caused by general corrosion or cracking. The existing fire protection program was given credit for managing this aging effect by reference to 27 fire protection procedures which monitor the active function of the system to determine its operability. The NRC team reviewed these procedures. There is no procedural requirement to monitor the system for general corrosion or to walk down the system piping to check for leakage caused by cracking. BGE depended on the monitoring program to reveal the aging effect. However the monitoring programs are macroscopic while the aging effect is microscopic. The aging effect may not be revealed because the effect is hidden by the error caused by the tolerance of the measuring device used to test or monitor the system. For example the calibration tolerance on a pressure gage used to derive flow for a system may introduce an error of thousands of gallons. This is what occurred in IR199600532 when a measured 10 psig variation in a flow test was investigated by an inquisitive technician. The technician discovered that a regulating valve, recently installed in the electric fire pump, was not closed and "in excess of 1000 gallons were flowing out of the system and not being measured." This could have been just as easily a corrosion breach of system 013 in an area not immediately available to a technician. For this reason the NRC team does not believe the fire protection program, by itself, can be credited for fully managing the effect of aging in system 013. The matter was documented in TPR 99-031, reviewed by the NRC, to change the AMR and LRA to include a system engineer walk down as part of the aging management program for the fire protections system.

Overall the NRC inspection team concluded Baltimore Gas and Electric properly implemented the aging management methodology approved by the NRC and the references and documentation supporting the information in the license renewal application are in auditable and retrievable forms. The NRC team also concluded there is reasonable assurance the effects of aging will be adequately managed in order to maintain the intended function(s) of the systems, structures, and components at Calvert Cliffs Nuclear Power Plant during the period of extended operation consistent with the current licensing basis.

Report Details

III. Engineering

E8 Miscellaneous Engineering Issues

E8.1 Aging Effects and Aging Management Program Review

a. Inspection Scope

The objective of this inspection was to evaluate the implementation and effectiveness of the activities supporting Baltimore Gas and Electric's (BGE) license renewal program. The inspection was structured to verify there is reasonable assurance the effects of aging will be managed adequately in order to maintain the intended function(s) of the systems, structures, and components at Calvert Cliffs Nuclear Power Plant (CCNPP) during the period of extended operation consistent with the current licensing basis (CLB). The NRC team verified BGE has implemented acceptable aging management programs that are consistent with their methodology and the information presented in their license renewal application (LRA) dated April 8, 1998. In addition, the inspection included verification that on-site information and documentation required by provisions of the rule or required to show compliance with the rule, was being maintained in an auditable and retrievable form, and was maintained consistent with NRC approved guidance for license renewal.

Consistent with the license renewal rule BGE used a deterministic approach to conduct an integrated plant assessment to ensure aging effects of systems, structures and components (SSC) was adequately managed. However, a plant specific Probabilistic Risk Assessment (PRA) can be used as an effective tool to provide integrated insights into the plant design, resulting in an additional relative measure of overall plant safety. The systems, structures, and components chosen by the NRC team, for closer inspection, used insights gained from Calvert Cliffs plant specific PRA in establishing the importance of the SSC to plant safety.

To maintain a consistent focus during the inspection, the NRC team selected specific plausible aging effects for the systems and structures listed below. The NRC inspection team reviewed a sample of maintenance records of the systems, structures and related commodity groups to identify any potential and plausible aging effects not identified by CCNPP in the LRA. The NRC team performed system walk downs for each of the systems and structures and reviewed the design, function, documentation, and aging management program for each selected aging effect to determine if BGE implemented their process consistent with their methodology and the rule. The following aging effects were considered for each system, component, and structure reviewed.

System/Component/ Structure	Potential and Plausible Aging Effects
Component Cooling Water (CCW)	Rubber Degradation, Selective Leaching, Flow Assisted Corrosion (FAC, a.k.a. erosion/corrosion or EC)
Non-Environmentally Qualified Cables	Cable Resistence and Impedance, Dynamic Load (conduit and boxes), Electrical Stress.
Control Room and Diesel Generator Building HVAC	Dynamic Loading, Microbiologically Influenced Corrosion (MIC), Wear
Safety Injection (SI)	Stress Corrosion Cracking, Fatigue, MIC
Component Supports	General Corrosion of Support Steel, Loading due to Hydraulic Vibration or Water Hammer, Loading due to Thermal Expansion of Piping/Component, Elastomer Hardening, Reciprocal Machinery Loading, Stress Corrosion Cracking of High Strength Bolting
Reactor Coolant System (RCS)	Erosion, Flow Assisted Corrosion, Galvanic Corrosion, Denting, Fatigue, Intergranular Attack, Stress Corrosion, Primary Water Stress Corrosion Cracking
Fire Protection	General Aging
Salt Water System (SW)	Galvanic Corrosion, Flow Assisted Corrosion, Elastomeric Degradation, Particulate Wear, Pitting.
Water Intake Structure	Aggressive Chemical Attack of Concrete, Corrosion (Crevice, Pitting, MIC, & General),Weathering
Primary Containment Building Structure	General Corrosion, Corrosion of Steel, Weathering, Corrosion of Tendons, Loss of Prestress, Corrosion of Refueling Pool Liner, Corrosion of Spent Fuel Pool (SFP) Liner
Auxiliary Building & Safety Related Diesel Generator Building Structure	Corrosion of Steel, Corrosion of SFP Liners, Degradation of Boraflex, Degradation of Carborundum, Weathering

Table 1, Systems, Components and Structures chosen for Inspection and the Aging Effects Examined.

b. Observations and Findings

Component Cooling Water

The NRC team reviewed Section 5.3 of Appendix A of the LRA, applicable portions of the NRC safety evaluation report (SER), and other plant documentation associated with the CCW. The NRC team interviewed BGE staff members, performed a review of BGE's CCW issue reports, reviewed the maintenance history of CCW, reviewed the preventive maintenance program for the CCW, and walked down the system while focusing on the aging management of rubber degradation, selective leaching and flow assisted corrosion.

Appendix A, Table 5.3-3 of BGE's LRA was a list of all potential and plausible aging effects identified by BGE. Included in the list was crevice corrosion, erosion / corrosion (a.k.a. flow assisted corrosion or FAC), general corrosion, pitting, rubber degradation, selective leaching, and wear. The NRC team reviewed the plausible aging effects, reviewed maintenance history and issue reports, and walked down the system. As a result of these activities, the inspection team verified there was reasonable assurance BGE identified all the plausible aging effects. No additional aging mechanisms were identified for the CCW.

BGE credited the Chemistry Control Program, Pump Overhaul and Inspection Procedure (Pump-14), LLRT STP M-571 E-1 and E-2, Preventive Maintenance (PM) Checklists (MPM01012, MPM01013, and MPM01143) and the age related degradation inspection (ARDI) Program with managing the aging of the CCW. The NRC team reviewed these documents and activities, and determined that Pump-14, and Checklists MPM01012, MPM01013, and MPM01143 lacked aging management requirements sufficiently focused enough to manage the applicable aging effects. Pump-14, for example, contained a reference to inspecting pump parts, however the reference was placed in the procedure in a manner that does not make it clear the pump casing is part of the pump being overhauled. Thus the passive portion of the pump assembly was not adequately managed. BGE issued a basis document that was intended to revise Pump-14 to address aging management, however this change was not implemented at the time of the inspection.

Review of CP-206 verified BGE had a process to control CCW chemistry to mitigate the effects of aging. The chemistry control process was designed to maintain CCW chemistry within specific limits. Review of CCNPP chemistry and issue reports verified CCW chemistry was maintained within the specified limits. For example, review of 1998 internal reporting records indicated BGE had not exceeded any action levels on CCW chemistry for the entire year.

The NRC team also reviewed CCNPP Administrative Procedure EN-1-118, "Age-Related Degradation Inspections of Mechanical Systems," Revision 0, and CCNPP Engineering Standard ES-045, "Age Related Degradation Inspection (ARDI) Program Technical Requirements Document for Mechanical Systems," Revision 00. These procedures were the basic procedures governing the ARDI program and did not implement the specific inspection requirements. The specific ARDI inspection activities for managing crevice corrosion, pitting, erosion corrosion, general corrosion, selective leaching, and wear in the CCW were not developed when this inspection was performed, and therefore, could not be verified by the inspection team.

BGE identified the plausible aging effects associated with CCW and implemented aging management programs consistent with the requirements of the rule, the information documented in its LRA, and the staffs evaluation as documented in the SER.

Non-Environmentally Qualified Cables and Electrical Commodities Groups

For convenience and efficiency of analysis, BGE chose to evaluate non-environmentally qualified (non-EQ) cables and electrical panels as commodity groups rather than to include the components with their respective systems. To verify BGE identified the applicable aging effects and developed aging management programs consistent with the provisions of 10 CFR Part 54, the NRC team reviewed several documents, including CCNPP License Renewal Application (LRA), Appendix A, Sections 6.1, "Cables," and 6.2, "Electrical Commodities," Calvert Cliffs aging management reviews, technical problem reports, maintenance records, and preventive maintenance checklists and procedures. The NRC team evaluated the potential and plausible aging effects, focusing on the aging management programs proposed by BGE. For the purposes of this inspection the NRC team specifically focused on cable stress, dynamic loading on conduits and boxes, and electrical stressors.

Appendix A, Table 6.1-2 of the LRA listed the potential and plausible age related degradation mechanisms (ARDM) for non-EQ cables. Six cable groups were identified based on combinations of cable types and ARDMs. Group 1 consisted of ethylene propylene (EPR), cross linked polyethylene (XLPE), and cross linked polyolefin (XLPO) cables in power and control service routed without maintained spacing. 60-year service limiting temperatures were calculated using Arrhenius modeling of industry experience data sets based on degradation of material properties using the methodology in Institute of Electrical and Electronics Engineers (IEEE) Standard 101-1987, "Guide for the Statistical Analysis of Thermal Life Data." The results of a cable temperature monitoring program then were compared to the 60-year temperature limits (reduced by a safety margin of 18 Fahrenheit degrees). BGE determined thermal aging was not plausible for this cable group. Using similar analyses, BGE determined that thermal aging was applicable to some EPR and XLPE cables in power service routed with maintained spacing (Group 2). Plausible aging effects also were identified for: (1) EPR/XLPE cables in power service routed inside the primary containment (Group 3 - synergistic radiation and thermal aging effects), (2) saltwater and service water system pump EPR motor terminations (Group 4 - thermal aging), and (3) EPR/XLPE/XLPO cables in instrument service (Group 5 - insulation resistance/impedance reduction). Cable treeing (voltage-induced micro channels) of EPR cables in continuous 4 Kilovolt power service (Group 6) was considered by BGE to be implausible because the cables were subject to electrical stress less than 100 Volts/mil. The team did not identify any additional plausible aging effects for non-EQ cables.

The electrical commodities consist of seven groups of electrical equipment structural enclosures including: (1) battery terminals and charger and inverter cabinets, (2) circuit breaker cabinets, (3) bus cabinets, (4) disconnect and switchgear cabinets, (5) motor control centers, (6) local control station panels, and (7) miscellaneous panels. The groups also include structural subcomponents and phenolic terminal blocks. The potential and plausible ARDMs are listed in Appendix A, Table 6.2-3 of the LRA. BGE identified general corrosion/fatigue, wear, and electrical stressors (ohmic heating effects on phenolic terminal blocks due to loose connections) as plausible ARDMs. The team did not identify any additional plausible aging effects for electrical commodities.

For group 4 saltwater and service water pump motor terminations, BGE was revising existing periodic electrical preventive maintenance tasks to include inspection for discoloration, crazing, cracking, or local embrittlement. The instrument calibration program was credited with compensating for gradual loss of insulation resistance/impedance due to cable aging. For synergistic radiation and thermal aging effects of EPR and XLPE power cables routed inside containment and routed outside containment with maintained spacing (Groups 2 and 3), BGE committed to a program to replace effected cables prior to functional failure.

Appendix A, Section 6.2 of the LRA stated that 125 volt dc chargers, inverters, and power distribution panels in Groups 3 and 7 would be examined either in the new ARDI program or in the existing PM program to identify elastomeric supports subject to aging degradation. The NRC team verified the commitment was captured in BGE's tracking system.

The Electrical Commodities Life Cycle Management Component Aging Evaluation Report credited existing PM checklists and procedures with managing plausible aging mechanisms, including general corrosion and fatigue, wear, and electrical stressors. The NRC team found many of the existing PM tasks did not provide the necessary level of detail to ensure the ARDMs were managed adequately. For example, EPM 05900, "480V Load Center and Transformer Cleaning and Inspection," which was credited for wear, fatigue, and electrical stressors in electrical commodities group 005-BUS-01, provided only general directions to "clean and inspect" the panels. Similarly, IPM 12103, "Clean and Inspect SR DAS Fans and Filters," (credited for group 020-PNL-01) directed only cleaning of the cabinet interiors and filters, and checking fans for proper operation. BGE provided sufficient documentation to show the PM checklists requiring revision to include additional guidance to cover the applicable ARDMs were identified and tracked. In addition, the ARDI program will be used to perform one-time inspections of electrical cabinets and panels that currently receive no periodic preventive maintenance in order to determine if significant plausible degradation mechanisms exist.

In Section 6.2 of the LRA, BGE stated internal operating temperatures in the 480 Volt motor control centers (MCCs) can approach the 60-year service limits for polyolefin insulated wiring and aging management would be needed for this plausible ARDM. The wiring would be included in Section 6.1, "Cables" of the LRA. However, Section 6.1 of the LRA stated internal p[illegible] wiring was not exposed to high temperatures and thermal aging was not plausible. Similarly, the electrical commodities section of the LRA stated that aging management of polyvinyl chloride bus splice boots in 4 Kilovolt switchgear would be covered with the cables commodity group. However, the boots were not discussed in Section 6.1 of the LRA. These contradictory statements were corrected in a revision to the AMR issued April 7, 1999. The NRC reviewed the revision and determined the corrections are appropriate.

Based on a detailed examination of several aging management activities planned by BGE for the cables and electrical commodities groups, the NRC team concluded specific aging management programs were being developed to manage the plausible aging effects.

Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning

The control room heating, ventilation, and air conditioning (CRHVAC) system provides ventilation to the control room, the cable spreading rooms, and the battery rooms. The diesel generator buildings ventilation (DGHVAC) systems serve the buildings that house the 1A emergency diesel generator and the station blackout diesel generator. The NRC team reviewed several documents to verify BGE identified all of the applicable aging effects and developed aging management programs consistent with the provisions of 10 CFR Part 54 for these systems, including: (1) CCNPP License Renewal Application (LRA) Appendix A, Section 5.11C, "Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems," (2) Calvert Cliffs Aging Management Review for the CRHVAC and DGHVAC systems, and (3) system walk down reports, technical problem reports (TPR), issue reports, and maintenance records. The NRC team also evaluated the potential and plausible aging effects, focusing on the aging management programs proposed by BGE for the subject systems; specifically focused on dynamic loading, MIC, and wear.

Appendix A, Table 5.11C-2 of the LRA listed seven plausible ARDMs BGE identified for the CRHVAC system, including general, crevice, and microbiologically induced corrosion, pitting, elastomer degradation, wear, and dynamic loading. The NRC team reviewed the SER, conducted system walk downs, and reviewed operating experience and maintenance history records to verify BGE identified all plausible aging effects. The NRC team did not identify any additional plausible aging effects for the system.

The relatively new DGHVAC system was placed into service approximately 20 years after the CRHVAC system and was designed with a life expectancy of 45 years. Because the system was at the relative beginning of its design life, BGE deferred aging management of the new equipment until lessons learned from aging management of the CRHVAC system evolved. SER confirmatory item 3.6.2.1.4-1 noted BGE needed to justify this position by confirming the environmental conditions and hardware configuration in the diesel generator building are similar to those in the control room system.

BGE identified routine system walk downs, its current PM program, and a new ARDI program as the aging management methods for the CRHVAC system. Routine system walk downs were conducted in accordance with procedure MN-1-319, "Structure and System Walk Downs," which provided general guidance for the inspection of the affects of corrosion and vibration, and specific guidance for the inspection of effects such as damaged supports, concrete and anchor bolt degradation, degraded protective coatings, and inadequate support, and inspection for the presence of standing water or accumulated moisture. BGE planed to revise the procedure to add specific inspection items to ensure discovery of ARDMs that apply to the CRHVAC system. Table 5.11C-3 of the LRA listed nine PM checklists BGE credited for discovery of aging effects. (The checklists also were discussed in Section 3.6.2.3.3 of the SER.) The NRC team found the current checklists would not manage the ARDMs and their effects in such a way that intended functions of the CRHVAC components would be maintained during the period of extended operation. For example, PM 09000 inspected fan belts and sheaves, PM 04169 inspected filters for cleanliness and greases motor and fan bearings, PM 09115 greased motors and fan bearings, and PM 09109 inspected fan V-belts. BGE provided Technical Problem Report #97-129, which identified the need to revise the PM checklists. The TPR recommended a specific line item be added to each PM task to inspect for general, crevice, and microbiological corrosion and pitting of fan housings, fasteners, heat exchanger housings, and damper metallic components, and for elastomer degradation and wear of fan elastomer seals. The ARDI program will perform a one time inspection of component interior surfaces, not otherwise inspected, to determine if significant degradation is occurring and additional inspections will be required.

Based on a detailed evaluation of several aging management activities planned by BGE for the CRHVAC system, the NRC team concluded specific aging management programs were being developed to manage the plausible aging effects. Lessons learned from the CRHVAC system program will be applied to the DGHVAC system.

Safety Injection System

The NRC team reviewed the following documentation to verify BGE identified applicable aging effects and aging management programs were developed or implemented consistent with the provisions of 10 CFR Part 54 for the safety Injection (SI) system: CCNPP LRA Appendix A, Section 5.15, safety injection system; Calvert Cliffs Aging Management Review for the SI system; boric acid corrosion inspection program; fatigue monitoring report for 1998; SI system health report cards; design changes; technical problem reports; root cause analysis reports; issue reports; site-maintenance records; interviewed engineering personnel; and, conducted SI system walk downs. This inspection focused on BGE's specific aging management programs associated with the aging effects of stress corrosion cracking, fatigue, and microbiologically influenced corrosion (MIC).

Appendix A, Table 5.15-2, of the LRA contained a list of seven potential and plausible age-related degradation mechanisms identified for the SI system. Included in the list of plausible aging effects for the SI system was crevice corrosion, fatigue, general corrosion, pitting, microbiologically-induced corrosion, stress corrosion cracking, and weathering. The NRC team reviewed the SER, conducted SI walk downs, reviewed operating experience information, and reviewed maintenance history records to determine if all plausible aging effects had been identified by BGE. The NRC team did not identify any additional plausible aging effects for the SI.

BGE credited the boric acid corrosion inspection program, fatigue monitoring program, chemistry control program, local leak rate test (LLRT), and the ARDI program with managing the aging effects of stress corrosion cracking, fatigue, and microbiologically influenced corrosion of the SI system. The NRC team reviewed the SI report cards, dated 9/11/98 and 12/9/98, and found the overall health of the SI was rated as Grade A for Unit 1 and Grade A for Unit 2. As a result of reviews of issue reports and design changes the NRC team determined BGE identified and resolved various design and operational concerns associated with the SI system, such as, replacement of the Low Pressure Safety Injection (LPSI) discharge check valves on both units with fast acting check valves in order to try and control the affects of water hammer transients caused by check valve slamming. Review of the fatigue monitoring program revealed BGE was recording transient data, calculating fatigue usage, and cumulative usage factors for the SI system/components. In addition, review of the In-Service-Inspection results for the SI system revealed BGE was properly monitoring critical locations of welds of high stresses welded attachments to the piping located between the Safety Injection Tank (SIT) outlet check valves and the loop inlet check valves at a location where thermal stratification was plausible.

The NRC team determined there is reasonable assurance BGE identified plausible aging effects in the SI system. Based on detailed evaluation of several aging management activities implemented by BGE for the SI system the NRC team determined BGE aging management programs are sufficient to manage plausible aging effects in the SI system.

Component Supports

The NRC team reviewed the following documentation to verify BGE evaluated applicable aging effects for component supports and aging management programs were identified, developed or implemented consistent with the provisions of 10 CFR Part 54: CCNPP LRA Appendix A, Section 3.1, Component Supports; Calvert Cliffs Aging Management Review Report for Component Supports; structure and system walk downs age related degradation inspection program; mechanical system walk down reports; technical problem reports; root cause analysis reports; Licensee Event Reports (LER); issue reports; interviewed engineering personnel; and, conducted plant and system walk downs. The NRC team reviewed plausible aging effects identified by BGE for component supports and evaluated aging management programs while focusing on the aging effects listed in Table 1 of this report.

LRA, Appendix A, Table 3.1-3, contains a list of potential and plausible ARDMs BGE identified for component supports. Included in the list of plausible aging effects for component supports was general corrosion of steel, loading due to hydraulic vibration or water hammer, loading due to thermal expansion of piping/components, elastomer hardening, loading due to rotating/reciprocating machinery, and stress corrosion cracking of high strength bolts. As a result of reviewing issue reports and LER 89-07 and 98-03 the NRC team determined water hammer and thermal expansion transient events had occurred at the Calvert Cliffs station. Section 3.1 of the LRA also indicated water hammer and thermal expansion events were observed at Calvert Cliffs. Even though BGE determined water hammer and thermal expansion occurred, BGE considered these aging effects not to be plausible for piping frames because the aging effects were not expected to prevent the piping frames from performing their intended support function. BGE's attempt to control water hammer by design, human performance, or procedure has not been successful as evidenced by repeated damage to Unit 1 pipe support R-16 in 1986, 1989 and 1998. BGE believes a design modification currently being installed to replace the SI pump discharge check valves with quick acting axial flow valves, on the Low Pressure Safety Injection (LPSI) system, may prevent or significantly reduce the water hammer condition. However, until loading problems due to water hammer or thermal expansion are brought under control the NRC team believes BGE should consider these plausible aging effects for piping frames and stanchions inside and outside containment. In addition, based on industry operating experience, the NRC team believes loading due to water hammer and thermal expansion can damage piping frames which can result in an overstress piping condition that may compromise the integrity of the piping.

The NRC team determined LRA, Appendix A, Table 3.1-3 should be revised to reflect these changes. BGE agreed with the NRC team finding and issued Technical Problem Report 99-035 to revise Table 3.1-3 to include loading due to water hammer for piping frames and stanchions inside and outside containment as a plausible aging effect. The NRC team reviewed TPR 99-035 and determined BGE did not include loading due to thermal expansion as a plausible aging effect. BGE agreed to take other related affects into account such as loading due to thermal expansion for piping frames and stanchions inside and outside containment.

Aging Management Review Report for Component Supports, Revision 3, dated January 1997, Section 2.2.8 did not include water hammer as an aging effect. BGE issued TPR 99-002 to identify water hammer as a plausible aging effect. The NRC team reviewed the TPR and considers BGE's actions acceptable.

The NRC team reviewed mechanical system walk down (MN-1-319) reports, for the SI, dated 11/24/98, 11/5/98, and 2/18/99. These walk downs were conducted by system engineers for the SI system and documented a number of deficient material conditions. Review of numerous issue reports and LERs indicated that BGE has been identifying and correcting component support deficiencies and is properly managing the plausible aging effects of component supports.

Except as noted above, the NRC team did not identify any additional plausible aging effects of component supports. These inspection activities indicated BGE's aging management programs for component supports were acceptably implemented. BGEs aging management programs were identified, developed or implemented acceptably and were consistent with the provisions of 10 CFR Part 54.

Reactor Coolant System

The NRC team reviewed the document Aging Management Review Report, Rev. 5, February 12, 1999, for the Reactor Coolant System (064), which presented the results of BGE's analysis of the reactor coolant system (RCS) to support license renewal. The NRC team focused on the aging affects listed in Table 1 of this report while reviewing the RCS system. The analysis concluded current programs, with minor modifications, were adequate to manage the effect of aging. The programs credited with managing aging were:

- Procedure MN-3-301, Boric Acid Corrosion Inspection Program, Rev. 2, change 0, 3/4/99
- Fatigue Monitoring Program
- Procedure MN-3-110, ISI of ASME Section XI Components, Rev. 3, 1/11/99
- CP-204, Specification and Surveillance of Primary Systems, (chemistry procedure)
- STP-0-27-1&STP-0-27-2, RCS Leakage Evaluation
- Alloy 600 Program
- Cast Austenitic Stainless Steel (CASS) Program
- STP-M-574, Eddy Current Exam Of CCNPP SNRC team Generators

The NRC team reviewed procedure MN-3-301 "Boric Acid Corrosion Program" and NDE-5710-CC "Visual Examination (VT-2) For Leakage", Rev 1, 10/28/97. The procedure required trained inservice inspection (ISI) engineers complete a containment walk down soon after reactor shutdown to Mode 3 or reactor cool down to Mode 5/6. The ISI engineer was required to look for evidence of RCS leakage in the form of white powder deposits of crystalized boric acid. These deposits are boric acid remnants left after coolant ablation. When evidence of boric acid leakage or general corrosion of an RCS component was discovered an Issue Report was prepared to document the condition and initiate corrective actions. During the current Calvert Cliffs outage BGE started using digital cameras to document boric acid leakage or component corrosion. The NRC team reviewed some of the digital photographs and Issue Report IR3-015-560 documenting the conditions found during the walk down of March 13, 1999. The use of a digital camera to establish a pictorial history of boric acid leakage should benefit the program by enhancing BGE's ability to trend conditions and identify repetitive leakage or corrosion.

The NRC team reviewed procedure EN-1-300 "Implementation of Fatigue Monitoring", Rev. 1 2/5/98, and discussed the program with the implementing engineer. This program is required by CCNPP technical specifications. The purpose of this program is to record, compile, and analyze thermal cycles in the fatigue limited components of the RCS and SI system, other ASME Class 1 piping, and feedwater piping adjacent to the steam generators. Critical locations in these systems had calculated design lifetime limits on the number of thermal temperature cycles caused by plant heat up, cool down and transients. To prevent component failure due to low cycle fatigue, the number of accumulated thermal cycles of critical components were tracked by the Fatigue Monitoring Program. An engineering analysis computer program used by the Fatigue Monitoring Program received plant operating data important to fatigue from the plant computer. The operating data was verified for accuracy, used to analyze transients, accumulated a partial cycle history of the critical locations in the piping, and compared to the design limits.

The NRC team examined the computer output data curves and tables for the year 1998 and reviewed the summary document Fatigue Monitoring Report for 1998. The report predicted the design limit of 55 loss-of-letdown transients will be exceeded, at the current cycle rate, for unit 1 before the end of the current 40 year operational life of the plant and will be exceed for both units during the extended operating period of license renewal. The report listed the current fatigue value as 46.778 effective full cycle transients. This number is derived from an analysis that accounts for past partial cycle transients when temperature differences and resulting fatigue do not meet the threshold of the parameters used in the design calculations. The report predicted, at the current rate, Unit 1 will have 117 and unit 2 will have 58 effective full cycle loss-of-letdown events after 60 years of plant operation. BGE contracted a detailed engineering analysis to review the validity of the current cycle counts and limits.

The limiting component for low cycle fatigue upon loss-of-letdown was a piping component in the charging line. This was caused by a loss of heat removal capacity from the regenerative heat exchanger as well as automatic throttling of charging flow which, in turn, caused thermal transients in the charging system piping. A detailed engineering study can be done of the charging system piping thermal transients using actual measured temperatures to test the validity of increasing the number of allowed cycles. BGE anticipates, based on early results, the cycle limit will be raised to 150 or greater for the loss-of-letdown transient.

The NRC team reviewed the procedure for ISI of plant components and discussed the program with program managers and engineers. The purpose of the program was to conduct a systematic non-destructive examination (NDE) of various plant components to detect early stages of deterioration in the form of crack initiation, and to confirm components were acceptable for continued use. The ISI sample selection in the RCS was predicated on ASME requirements, component performance history, and industry experience. The examination of RCS piping was focused on the welds and areas adjacent to the welds. In the case of CCNPP, 25% of the RCS welds were examined during the ASME ten year inspection interval. The welds with structural discontinuities were chosen first as candidates for the sample set and then welds were chosen based on ASME rules for stress location, sample distribution, piping vulnerabilities, etc, until 25% of the population was selected. This sample was then examined in each succeeding ten year inspection interval. The NRC team evaluated CCNPP RCS weld maps and the ISI long term plan and determined ISI was performed on 104 out of 205 existing welds in the main RCS. This population was the limit required for ASME compliance. The larger question of accepting ASME Section XI ISI as an age management system in general was being considered by the NRC Office of Nuclear Reactor Regulation.

The ISI methods used are a combination of liquid penetrant testing (PT) to detect cracks on the external surface and ultrasonic testing (UT) to detect cracks located in an area of one third wall thickness from the inside surface of a weld. In addition to the 25% sample of the welds CCNPP engineers stated NDE was also performed on various components where problems were suspected. For example a one time NDE examination was conducted on the pressurizer spray line. In addition visual inspections were performed on the external surface of valves and PT was performed on the outside surface of reactor coolant pumps.

The NRC team asked the BGE engineers what problems were discovered by ISI and was told CCNPP hadn't found an indication in or on the RCS piping. This experience is consistent with industry reports. The BGE engineers recalled minor corrosion on a bimetallic weld adjacent to a pump casing discovered during penetrant testing of the casing. The cause of the corrosion was boric acid leakage and was remediated. The NRC team questioned whether any NDE techniques were applied to the RCS piping to detect wall thinning or other degradation. BGE replied that none was necessary because good water chemistry coupled with RCS internal stainless steel cladding made erosion insignificant.

The NRC team toured accessible areas of the interior of the containment building of Unit 2 with the RCS System Manager. A ten year ISI inspection was in progress on the reactor vessel. The NRC team observed the in-vessel NDE equipment used to examine the vessel. Outside containment the NRC team observed vessel examination data acquisition in progress. The NRC team discussed work methods and results with responsible NDE engineers and concluded the reactor vessel NDE examination was acceptable.

The NRC team discussed the Alloy 600 program with a knowledgeable engineer. BGE stated in the license renewal application Stress Corrosion Cracking (SCC) and Intergranular SCC were plausible aging effects for RCS piping sub-components fabricated from Inconel 600 ® alloy metal. The Alloy 600 program was a program for monitoring and compiling industry experience of flaws in components made from Inconel.

Thermal embrittlement was stated by BGE to be a plausible aging effect for RCS piping and sub-components fabricated from cast austenitic stainless steels (CASS). BGE stated a new program will be developed to identify CASS components in the RCS and perform an engineering evaluation of the components suitability for service during an extended period of operation. Because the program has not been developed, the NRC team did not review it.

The NRC team discussed the program for eddy current testing of steam generator tubes with the System Manager of SG Eddy Current Testing. The steam generators for both units are scheduled for replacement. Unit 1 is scheduled for replacement in 2002 and Unit 2 in 2003. Therefore no long term aging management exists to manage aging effects of the SGs beyond the scheduled replacement. The NRC team reviewed the current conditions and problems. Engineers stated tubes removed from service by plugging are now 9-10% of the total in Unit 1 and 12-13% of the total in Unit 2 and plant operation is feasible with plugging up to 30%of the total per SG. The types of tube indications experienced were stress corrosion cracking (SCC) in the axial direction, denting with circumferential cracking at the dent, and primary water SCC in the tube sheet area. The criteria for removing a tube from service was to plug any tube with crack indications or wall lose greater than 40% of wall thickness. The SG tube inspection program, though not directly applicable to license renewal, is acceptable.

The AMR for RCS Group 064-CC-01 credits the ISI program with managing primary water stress corrosion cracking (PWSCC), (not stress corrosion cracking and stress corrosion cracking intergranular as defined in the LRA) in the RCS. The ISI program can not fully cover the aging affects in the RCS. For example the ISI program is credited with managing the aging affects in the Pressurizer Sample Nozzle Neck (PSNN) when this component is exempted by ASME because the PSNN is one of the "components that are connected to the reactor coolant system and part of the reactor coolant pressure boundary, and that are such a size and shape so that upon postulated rupture the resulting flow of coolant from the reactor coolant system under normal plant operating conditions is within the capacity of makeup system that are operable from on-site emergency power". This specific issue was addressed in TPR 99-032 which removed the ISI program from aging management of the RCS system. Instead the aging effects will be managed by the existing Alloy 600 program which must be modified to include all the possible locations not currently interrogated by the program such as the Inconel thermal sleeves in the Reactor Vessel nozzles. In addition BGE corrected the terminology used in the LRA and AMR from Stress Corrosion Cracking and Stress Corrosion Cracking (Intergranular) to the generally accepted nomenclature of PWSCC. With this exception the NRC team concluded the aging management programs described by BGE in the license renewal application were acceptable.

Fire Protection

Fire protection includes two functions. The fire protection function included equipment and facilities that detect, fight and extinguish fires. The safe shut down function consisted of the systems used to bring the plant to a safe condition in the event of a severe single fire located in the plant by providing reactor coolant system pressure and inventory control, reactivity control, reactor coolant system heat removal in hot standby or cold shut down, and process monitoring. An aging management review was done on the non-safety related pressure retaining portions of systems that perform fire protection. The aging management review of the safety related pressure retaining portion of the systems was covered as a consequence of the review performed because of the systems primary function; not its fire protection or safe shut down function. These reviews identified twenty systems that participate in fire protection of which four systems were fully bounded by their safety related pressure boundary and one had no pressure retaining requirement. The following systems were discussed under their primary function elsewhere in this report : salt water, component cooling, auxiliary feedwater, safety injection, and reactor coolant.

For the well and pretreated water system, the direct water source for the fire protection system, the credible aging effect was pressure boundary degradation caused by localized or general loss of material through erosion or corrosion or a combination of these aging mechanisms. BGE took credit for the Fire Protection Program surveillance inspections of the systems as managing the effects of aging in both the well and pretreated water system and fire protection system. The fire protection system included two auxiliary systems: the Halon 1301 system protecting the cable spreading room and the foam suppression system. The aging of these systems were also managed by their related surveillance inspections. These regular inspections constituted a sufficient level of monitoring to capture the effect of aging on these systems.

The compressed air system provided instrument air and plant air subsystems. This system supplied air to pneumatic instruments and controls and pneumatically operated containment isolation valves. In the event of the compressed air system failure the instrument air system would be supplied by the plant air system through a tie between the plant air system header and the instrument air system. The transition between the systems was supported by air storage tanks providing approximately 20 minutes reserve. The normal operational requirements placed on the compressed air system were more stringent than the requirements the compressed air system had to meet to perform its fire protection function. Because the requirements for normal operation were more stringent, the aging management of the system was fully bounded by its safety related portions under its normal operation. BGE, therefore, does not need a separate aging management program for the fire protection function of the compressed air system because it was adequately addressed by the aging management program for the compressed air system's performance of its safety function.

The closed service water cooling system removed heat from turbine plant components, blowdown recovery heat exchangers, containment cooling units, spent fuel cooling heat exchangers, and emergency diesel generator heat exchangers. The service water cooling system divided into two subsystems in the auxiliary building to meet single failure criteria. The system was used for safe shutdown by providing the cooling water to emergency diesel generators, containment air coolers, instrument air compressors, and plant compressors. The parts of the service water system that supply cooling to the diesels and containment air coolers were safety related and had separate aging management programs for the safety function. The fire protection aging management was limited to the cooling supplied to the 1A and PA air compressors in the turbine building. BGE determined the requirement for normal operation of the service water cooling system was the same as the requirement for the system under safe shut down conditions and concluded "any degradation in the pressure retention capability of the non-safety related flow paths would manifest itself in the form of leakage that, if left unmitigated, would have an adverse effect on power production capability. For this reason, prompt identification and corrective action can be assured. No further evaluation of these components is warranted." This appeared to react to the results of degradation caused by an aging mechanism instead of managing the aging mechanism itself. As a result of an NRC request for additional information during the safety evaluation review process, BGE, in their first annual update of April 2, 1999, changed this statement to read, "To ensure that the nonsafety-related Turbine Building SRW (ed. service water) piping maintains its seismic adequacy, the SRW ARDI (ed. age related degradation inspection) for erosion corrosion will include the nonsafety-related piping serving Turbine Building loads." The nonsafety-related Turbine Building SRW was the portion of the piping of the service water system that supplies cooling to the 1A and PA air compressors.

The diesel oil system supplied fuel to the emergency diesel generators, auxiliary boilers, and the diesel-driven fire pumps; all used during either safe shut down or detection, fighting or suppression of fires. The parts of the diesel oil system not encompassed by a safety function review, and therefore requiring an aging management review under the fire protection function, were the piping and components related to the diesel-driven fire pump. The piping and components which supply diesel fuel oil to the diesel-driven fire pump "day" tank are all non-safety. Because the fire protection program performed periodic surveillance, testing, and disassembly of the diesel driven fire pump, degradation of the pressure boundary of the diesel fuel oil system would be evidenced by degraded performance. The degree to which the fire protection system is monitored made this an acceptable approach.

Plant heating, plant drains, and liquid waste have fire protection functions. Except for check valves identified in the plant drain system designed to prevent the back flow of combustible liquids to safety related areas, the testing of the systems and components during normal operation adequately demonstrated the fire protection function of the system.

There are 13 electrical systems listed in table 5.10 - 1 of the BGE LRA with components that performed fire protection functions that were active. Those systems required no further evaluation because the remaining intended function that are passive, i.e. electrical continuity and component support, were addressed in other commodity evaluations. This section of the LRA listed, among the 13 electrical systems, the fire and smoke detection system as one requiring no further review because its passive function is addressed in a commodity evaluation. The aging management review, dated January 29, 1997, however concluded the fire and smoke detection system required no further review because it had no pressure retention requirements even though it identified functions LR096-01 and LR096-02 as active electrical signals "which requires motion or change of state of system components". The conclusion submitted in the LRA for the fire and smoke detection system was not supported by the analysis developed in the ARM for the same system. The NRC team reviewed TPR 99-031 which resolved this matter by changing the AMR conclusion to correspond with the correct statement in the LRA.

In the fire protection AMR, for fire protection system 013, the plausible aging effect of pressure boundry degradation caused by general corrosion or cracking was identified. The existing fire protection program was given credit for managing this aging effect by reference to 27 fire protection procedures which monitor the active function of the system to determine its operability. The NRC team reviewed all these procedures. There was no procedural requirement to monitor the system for general corrosion or walk down the system piping to check for leakage caused by cracking. BGE depended on the monitoring program to reveal the aging effect. However the monitoring programs were macroscopic while the aging effect was microscopic. The aging effect may not be revealed because the effect was hidden by the error caused by the tolerance of the measuring device used to test or monitor the system. For example the calibration tolerance on a pressure gage used to derive flow for a system may introduce an error of thousands of gallons. This is what occurred in IR199600532 when a measured 10 psig variation in a flow test was investigated by an inquisitive technician. The technician discovered a regulating valve, recently installed in the electric fire pump, did not close and "in excess of 1000 gallons were flowing out of the system and not being measured." This could just as easily have been a corrosion breach of system 013 in an area not immediately available to a test technician. It is for this reason the NRC does not believe the fire protection program, by itself, can be fully credited for managing the effect of the aging. The matter was corrected in TPR 99-031, reviewed by the NRC team, to change the AMR and LRA to include a system engineer walk down as part of the aging management program.

Salt Water System

The NRC team reviewed Section 5.16 of Appendix A of the LRA, applicable portions of the SER, and generic communications associated with saltwater systems. The NRC team also interviewed BGE staff members, performed a review of the applicant's issue reports relating to Saltwater, reviewed the maintenance history of SWS, reviewed the preventive maintenance program for the SWS, and inspected the intake channel to the SWS.

Although the NRC team reviewed the entire SWS aging management program, this inspection focused on the aging management program for galvanic corrosion, flow assisted corrosion, particulate wear, elastomeric degradation, and pitting. Because of operating history and SWS design, additional attention was paid to potential aging associated with graphitic corrosion and aging management of underground piping.

Appendix A, Table 5.16-3, of the LRA, contained a list of all potential and plausible aging effects identified by the applicant. Included on the list of plausible aging effects was galvanic corrosion, erosion / corrosion, particulate wear, elastomeric degradation, and pitting. The SER indicated BGE also identified selective leaching (e.g., graphitic corrosion), radiation damage, and wear as plausible aging effects. Review of the application verified BGE never considered selective leaching, radiation damage or wear as plausible aging effects for the SWS.

In general, BGE used its Preventive Maintenance (PM) Program to manage the aging associated with the SWS. BGE primarily relied on repetitive tasks and checklists to implement aging management activities. BGE also referenced technical and administrative procedures for implementing the PM program. A review of the repetitive tasks and checklists identified numerous condition monitoring activities credited with managing the various aging effects. Although BGE indicated three of the more than fifty procedures, repetitive tasks, and checklists need to be revised for license renewal, BGE demonstrated there is reasonable assurance the effects of aging from galvanic corrosion, erosion / corrosion, particulate wear, elastomeric degradation, and pitting will be adequately managed during the period of extended operation.

In 1984, BGE identified ongoing graphitic corrosion of their cast iron saltwater piping. As described in NRC Information Notice 84-071, graphitic corrosion is where an electrolytic cell is established between the graphite and iron within the cast iron material in the presence of water containing dissolved salts. The iron is dissolved leaving just the graphite structure of the metal behind which is highly permeable to water and has no strength.

Originally, the phenomena was identified as a result of through-wall leaks in the saltwater-side of the Unit 1 component cooling system heat exchanger. Further investigation verified this condition existed on both units and was not limited to the component cooling heat exchangers. A maintenance history review verified BGE spent significant resources throughout the 1980s and early 1990s to mitigate the effects of graphitic corrosion and other aging effects associated with the harsh environment of the SWS. In the early 1990s BGE replaced sections of above ground saltwater piping with rubber-lined carbon steel piping. Many of the components (e.g., valves, pumps, specialty piping such as the "ram's head") were either replaced with titanium, stainless steel, or other corrosion resistant materials, or were repaired and coated with coal tar or Belzona epoxy materials. The only notable exception in this process was the under ground supply and discharge headers.

The underground piping is cast iron with an internal mortar lining. The outside of the underground piping is insulated from the soil and protected from its applicable aging effects by multiple layers of wrap, enamel coating, and cathodic protection. In response to GL 89-13, "Service Water System Problems Effecting Safety-Related Equipment," BGE committed to inspecting and repairing its underground piping. This effort was initiated in 1993. The interior surface of the piping was manually scraped and vacuumed cleaned. The adherence of mortar lining was tested by hammering the lining to detect and remove loose mortar. Exposed surfaces were cleaned and ultrasonically tested to determine wall thickness. More than 600 areas of defective mortar were found ranging from about the size of a quarter to a couple of square feet. Graphitic corrosion and other aging effects were occurring in many of these exposed locations, however, ultrasonic testing verified no loss of pipe-wall thickness below design minimum wall. The SWS underground piping was located below the turbine building and could not be excavated to inspect the exterior of the pipe. The ultrasonic testing at more than 600 locations from inside the piping demonstrated reasonable assurance the exterior coating was effectively controlling the aging of the exterior pipe. The applicant had multiple repetitive tasks to periodically clean, inspect, and ultrasound and repair damage mortar lined cast iron piping which provided reasonable assurance the effects of aging from graphitic corrosion will be managed during the period of extended operation.

Leaching of the Salt Water System was not considered plausible in the CCNPP LRA yet there was an extensive program at CCNPP to remediate the effect of this corrosion in the SW system. The conclusion that leaching was not plausible was inconsistent with the amount of leaching present and the program in place to take care of it. The NRC team does not agree with the BGE conclusion. TPR 99-030 was generated to include leaching as a plausible aging mechanism and the NRC has reviewed the report.

Structures

Structures reviewed during this site inspection included: the Water Intake, Primary Containment, Auxiliary Building, and the Safety-Related Diesel Generator Building. The focus of the site inspection effort was the review, verification and the auditibility of the documentation associated with the structural aging management process used by BGE. All aging effects identified by BGE were reviewed, if plant conditions allowed, and any aging effects not identified by BGE were noted during the walk downs and visual inspection of the above structures.

BGE'S process for evaluating the effects of aging on structural components types (e.g. concrete beams and slabs, steel beams, base plates, watertight doors) within the scope of license renewal was completed in accordance with BGE procedure, "Component Aging Management Review Procedure for Structures," EN-1-305, Revision 1. The evaluation was accomplished by the following steps:

(1) Identification of potential aging mechanisms for each structural component type,

(2) Identification of plausible component aging mechanisms for each structural component type or specific components within the component type based on the following: environmental conditions, material of construction, and impact on intended functions,

(3) Development of attributes for programs to manage the effects of aging from those ARDMs identified as plausible, and

(4) Evaluation of program adequacies to demonstrate that the effects of aging will be managed so that the intended function(s) will be maintained for the period of extended operation.

The applicable ARDMs identified by BGE for the building structures were corrosion of steel, corrosion of tendons, degradation of concrete elements (freeze-thaw, leaching, etc.), cracking of masonry walls, corrosion of concrete reinforcement, corrosion of liner, corrosion of permanent cavity seal ring for refueling pool, tendon prestress losses, general corrosion and oxidation of penetrations (fuel transfer tube/bellows, personal/emergency air lock and equipment hatch), weathering of grout, weathering of caulking and sealants, foundation settlement and degradation of carborundum and boraflex materials.

Containment

During the NRC team walk down of containment, while traversing the auxiliary building roof, cracks were observed at buttresses three (150 degree) and four (210 degree) of Unit 1. The cracks originate at the tendon end caps and appear to migrate to the opposite side of the buttress. This cracking appears to be an observed aging effect the BGE LRA excludes. BGE will have an aging management program in place by September of 2001 under the accelerated implementation of ASME Section XI, Subsection IWL by rule 50.55a (g) (6) (ii) (B) which will manage this aging effect; for which BGE can take credit. The NRC does not agree with BGE's conclusion that cracking of containment is not a plausible aging effect. BGE took up this matter and determined the cracks identified in Unit 1 may lead to corrosion of steel reinforcement bars. TPR 99-036 was issued and BGE agreed corrosion of impeded steel reinforcement is plausible and will manage the effects thru MN1-319. Minor leaching of calcium hydroxide on the Unit 2 concrete containment dome was noticed in about five locations.

During the NRC team walk down of the Unit 2 containment building interior it was noted that several attachments on the inside dome liner and cylinder wall were of a different color than the containment liner and appeared to be rusting. Upon closer examination of these attachments (abandoned snubber connections and attachments for the integrated leak rate test measurement devices) it was determined the attachments were painted a different color and were not rusting. However, other minor chips and flaking of the containment liner paint were noted, which the applicant indicated would normally be repaired as required by the "Containment Visual Inspection," STP-M-665-1 procedure. It was also noted that the applicant had replaced the expansion joint material (Thiokol Polysulfide) between the floor slab and the cylinder liner plate with a new high-density silicon elastomer because the old joint material had degraded. The same expansion joint corrective action had been completed for Unit 1 in 1996. All visible penetrations such as the personnel airlock, and equipment hatch appeared to be in good working order and no corrosion was noticed.

Finally, during the walkdown of the Unit 2 Tendon Access Gallery about 15 corroded nuts located on the tendon end caps as well as the extrusion of several (about 12) rubber gaskets located between the tendon end cap and the bearing plate were noted. Several cracks in the concrete vertical walls of the Tendon Gallery were noted, these cracks allow water to enter into the Tendon Gallery (note that the Tendon Access Gallery is not within the scope of License Renewal). The corrosion of the tendon end cap nuts and the extrusion of the rubber gasket material will be addressed by the NRC staff under the 10 CFR 50 requirements.

Auxiliary

BGE considered that cracking of Masonry Walls was a potential aging mechanisms but determined that it was not plausible based on the findings of a walkdown performed in November, 1994. As stated in Appendix I of the "Aging Management Review Report for the Auxiliary Building Structure," revision 4, May 1998, " BGE inspected the accessible portions of approximately 15 walls and found no cracks, cracking of Masonry Walls is not a plausible aging mechanisms." Therefore, BGE concluded in the AMR report for the Auxiliary Building, Appendix J, paragraph 2.5, that settlement was not plausible. However during the NRC walk down diagonal through wall cracks were observed on the concrete wall for the Unit-1, 5 foot elevation, Fan Room, south of Door number 212. Also in an Issue Report Resolution Document (IRRD) IRI-024-713 dated 9-20-1996, addressing the operability of a pipe support in the Auxiliary Building with a crack running diagonally under the support, the IRRD concluded "the diagonal cracking in this wall appears to be the result of settling of the Auxiliary Building. " The conclusion of the IRRD does not support the conclusion arrived at in the AMR for the Auxiliary Building. This contradiction was pointed out and discussed with BGE. BGE issued TPR 99-037 on April 15, 1999 to address this issue (which will revised Appendix J of the AMR to indicate that cracks in the building were due to initial settlement and that Section 3.3E of the LRA which currently states that no cracks were observed is incorrect. The NRC considers this matter closed.

Water Intake

BGE determined for the Intake Structure that all structural components were subjected to an Aging Management Review (AMR). Table 3.3C-3 of Appendix A to the LRA shows the component types and their identified ARDMs. The plausible ARDMs are: 1) weathering of caulking and sealants, 2) weathering of expansion joints, 3) corrosion of steel components, 4) corrosion of sluice gates, and 5) aggressive chemical attack on concrete and corrosion of steel reinforcement for fluid - retaining walls and slabs. A detailed discussion for all ARDMs, existing, modified, and new aging management programs, along with recommendations for future action was provided in the "Aging Management Review Report for the Intake Structure," revision 4, August 1998, the NRC inspection team found this write-up acceptable. A visual inspection of the fluid-retaining walls and slabs of one of the dewatered Unit 2 Intake Cavities showed normal concrete aging and revealed no new ARDMs.

Except as noted previously the NRC team concluded the aging management of the CCNPP structures is adequate.

c. Conclusions

The inspection revealed a few aging effects that were not taken into account such as water hammer and thermal expansion loading or structural cracking. All the omitted aging effects identified by the NRC team were entered into the licensee corrective action program by the Life Cycle Management staff at Calvert Cliffs Nuclear Power Plant.

The NRC team concluded that in many cases existing procedures or programs, given credit for aging management, are not able to completely manage the aging effect. The process of integrating aging management into the existing programs is being developed and there is evidence of a neoteric system that will take care of these problems.

Overall the NRC inspection team concluded that Baltimore Gas and Electric properly implemented the aging management methodology approved by the NRC and the references and documentation supporting the information in the license renewal application are in auditable and retrievable forms. The NRC inspection also concluded there is reasonable assurance the effects of aging will be adequately managed in order to maintain the intended function(s) of the systems, structures, and components at Calvert Cliffs Nuclear Power Plant during the period of extended operation consistent with the current licensing basis.

V. Management Meetings

X1 Exit Meeting Summary

The NRC inspection NRC team presented the results of the inspection to members of BGE's management at the conclusion of the inspection on April 16, 1999. BGE acknowledged the findings presented and acknowledged that the inspection findings did not contain proprietary information.

PARTIAL LIST OF INDIVIDUALS CONTACTED

BGE

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P. Crinigan	Outage Manager
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NRC

P. Kuo	Section Chief, NRR
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D. Soloreo	Project Manager, NRR
W. Ruland	Acting Deputy Director, RI

INSPECTION PROCEDURES USED

IP 71002 License Renewal Inspection Procedure

LIST OF ACRONYMS USED

AMR	Aging Management Report
ARDI	Age Related Degradation Inspection
ARDM	Age Related Degradation Mechanisms
ASME	American Society of Mechanical Engineers
BGE	Baltimore Gas and Electric
CASS	Cast Austenitic Stainless Steel
CCW	Component Cooling Water
CCNPP	Calvert Cliffs Nuclear Power Plant
CLB	Current Licensing Basis
CRHVAC	Control Room HVAC
DGHVAC	Diesel Generator Building HVAC
EPR	Ethylene Propylene
ESF	Engineered Safety Feature
ESP	Engineering Service Package
FAC	Flow Assisted Corrosion
HVAC	Heating Ventilation and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IPA	Integrated Plant Assessment
IRRD	Issue Report Resolution Document
ISI	Inservice Inspection
LER	Licensee Event Report
LPSI	Low Pressure Safety Injection
LRA	License Renewal Application
MCC	Motor Control Center
MIC	Microbiologically Influenced Corrosion
NDE	Nondestructive Evaluation
PM	Preventative Maintenance

PRA	Probabilistic Risk Assessment
PT	Liquid Penetrant Testing
PWSCC	Primary Water Stress Corrosion Cracking
RAI	Request for Additional Information
RCS	Reactor Coolant System
SG	Steam Generator
SCC	Stress Corrosion Cracking
SER	Safety Evaluation Report
SI	Safety Injection
SIT	Safety Injection Tank
SRDG	Safety Related Diesel Generator
SSC	Systems, structures, and Components
SW	Salt Water System
TPR	Technical Problem Report
UT	Ultrasonic Testing
VAC	Volts Alternating Current
UFSAR	Updated Final Safety Analysis Report
XLPE	Cross Linked Polyethylene
XLPO	Cross Linked Polyolefin