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Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools

B&W Owners Group Generic License Renewal Program, BAW-2270, Revision 2, 1999

Technical Report

Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools

B&W Owners Group Generic License Renewal Program, BAW-2270, Revision 2, 1999

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REPORT SUMMARY

As part of the application process for license renewal, nuclear utilities must perform an evaluation to confirm that they have appropriately considered any aging effects on plant components. A management plan must be developed for all components subject to aging effects. This report presents a set of mechanical tools for utility use in determining which aging effects are applicable to Non-Class 1 mechanical components.

Background

Non-Class 1 mechanical components include those that are not within the ASME Section XI, Subsection IWB, Class 1 Inservice Inspection (ISI) boundary. Documentation of the components subject to an aging management review (AMR) is plant-specific and requires consideration of materials, environment, and component intended function. The Babcock and Wilcox (B&W) Owners Group conducted this research to help utilities identify applicable aging effects associated with Non-Class 1 mechanical components subject to AMR for license renewals.

Objective

To develop a set of material- and environment-based rules to help utilities identify locations where aging effects may apply in Non-Class 1 mechanical components.

Approach

Due to the similarity of material and environmental conditions for mechanical components subject to AMR, the project team developed a set of rules for determining whether certain material/environment combinations could result in age-related degradation in Non-Class 1 mechanical components. The components addressed in these rules include: 1) heat exchangers, 2) tanks/vessels, 3) pumps, 4) valves, 5) piping, tubing, fittings, and branch connections, and 6) miscellaneous process components. The team also developed other specialized tools for evaluating bolted closures and fatigue. Aging effects evaluated include cracking, loss of material, reduction in fracture toughness, distortion, and loss of mechanical closure integrity. Environmental conditions considered include treated water, raw water, gas, oil and fuel oil, and external ambient environments.

Results

The mechanical tools included in this report are a set of rules—summarized in flow charts and tables—that allow utilities to identify aging effects for a given Non-Class 1 mechanical component based on material and environment. These material- and environment-based rules are derived from known age-related degradation mechanisms and operating experience. In developing the rules, the states of stress in the mechanical components were typically not known. Developers assumed, however, that mechanical components experience residual stresses due to

fabrication, field installation, and field welding. This approach resulted in a conservative set of rules for assessing applicable aging effects.

EPRI Perspective

This report presents tools for helping utilities identify applicable aging effects for Non-Class 1 mechanical components. For license renewal purposes, utilities must also review existing programs to determine proper management of aging effects in order to maintain component intended functions during extended operation. In most instances, existing plant programs will likely be sufficient to manage the applicable aging effects. However, in circumstances where existing programs do not fully ensure such management, additional actions may be required for license renewal. EPRI is considering future updates of the report to provide an industry standard reference for evaluation of Non-Class 1 mechanical components subject to AMR for license renewal. Related EPRI work includes Aging Effects for Structures and Structural Components (Structural Tools), TR-114881.

TR-114882

Keywords

Non-Class 1 mechanical components
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Executive Summary

The Non-Class 1 Implementation Guideline and Mechanical Tools deal exclusively with Non-Class 1 mechanical components subject to an aging management review in accordance with the requirements of 10 CFR Part 54.21. Non-Class 1 mechanical components include those mechanical components that are not within the ASME Section XI, Subsection IWB, Class 1 ISI boundary.

Due to the similarity of materials and operating environments for mechanical components subject to an aging management review, a set of material and environment based rules was developed to identify locations where aging effects (e.g., cracking, loss of material, reduction in fracture toughness, distortion, and loss of mechanical closure integrity) may be applicable. Operating environments for mechanical systems within the scope of license renewal may be divided into treated water, raw water, gas, oil and fuel oil, and external ambient environments. The tools for these material and environment combinations are found in Appendices A through E. In addition, specialized tools were developed for heat exchangers, bolted enclosures, and fatigue and are found in Appendices F though H. For license renewal considerations, once the applicable aging effects are identified using the material and environment based rules, utilities must then review existing programs to ensure that the identified aging effects are managed so that component and system intended function(s) are assured in the period of extended operation.

The Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools include a list of Non-Class 1 mechanical components, a description of the development of material and environment based rules to address aging effects, and guidance on demonstration of aging management. The material and environment based rules are attached as appendices to this document.

IMPLEMENTATION GUIDELINE

ACRONYMS

AIF................. Atomic Industrial Forum
AMR.............. Aging Management Review
AMG.............. Aging Management Guideline (Sandia National Lab. Document)
ASME............ American Society of Mechanical Engineers
AWWA .... American Water Works Association
B&W .... Babcock & Wilcox
B&WOG........ Babcock & Wilcox Owners Group
BWR.............. Boiling Water Reactor
BWROG........ Boiling Water Reactor Owners Group
BL.................. IE Bulletin (from the NRC)
BWNT........... B&W Nuclear Technologies
BWR.............. Boiling Water Reactor
CASS............. Cast Austenitic Stainless Steel
CFR .... Code of Federal Regulations
CLB .... Current Licensing Basis
CR .... Circulars (from the NRC)
CRDM........... Control Rod Drive Mechanism
ECCS............. Emergency Core Cooling System
EPRI .... Electric Power Research Institute
FCAW .... Flux Core-Arc Welding
FEMA............ Federal Emergency Management Agency
FIV................. Flow-Induced Vibration
GE.................. General Electric
GL.................. Generic Letter (from the NRC)
GLR .... Generic License Renewal
GLRP............. Generic License Renewal Program
GMAW.......... Gas Metal-Arc Welding
GTAW........... Gas Tungsten-Arc Welding
HAZ............... Heat Affected Zone
HPI .... High Pressure Injection
IASCC .... Irradiation-Assisted Stress Corrosion Cracking
IE .... Inspection and Enforcement (NRC)
IGA................ Intergranular Attack
IGSCC .... Intergranular Stress-Corrosion Cracking
IN................... Information Notice (from the NRC)
IPA .... Integrated Plant Assessment
ISI .... Inservice Inspection
LER .... Licensee Event Report
LPI................. Low Pressure Injection

MIC .... Microbiologically-Influenced Corrosion
MPC .... Material Properties Council
MSS .... Manufacturer's Standardization Society
NEI .... Nuclear Energy Institute (formerly NUMARC)
NPRDS .... Nuclear Plant Reliability Data System
NPSH .... Net Positive Suction Head
NRC .... U.S. Nuclear Regulatory Commission
NUMARC ..... Nuclear Management and Resources Council (now NEI)
PAW .... Plasma-Arc Welding
PWR .... Pressurized Water Reactor
PWSCC .... Primary Water Stress Corrosion Cracking
RB .... Reactor Building
RCP .... Reactor Coolant Pump
RCS .... Reactor Coolant System
SAW .... Submerged Arc Welding Process
SCC .... Stress Corrosion Cracking
SCs .... Structures and Components
SMAW .... Shielded Metal Arc Welding Process
SOC .... Statement of Consideration
SSCs .... Systems, Structures, and Components
TGSCC .... Transgranular Stress-Corrosion Cracking
TLAA .... Time-Limited Aging Analyses

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DEFINITIONS

The definitions for many of the terms used throughout this document are contained in 10 CFR Part 54 and are not repeated here.

Component Intended Function(s) are those component level functions that support system level intended functions.

Intended Function(s) are system, structure, and component functions required to demonstrate compliance with the requirements defined in 10 CFR 54.4 (i.e., safety-related, SSCs relied upon to remain functional during and following design-basis events, nonsafety related SSCs whose failure could prevent accomplishment of safety-related functions, and SSCs relied upon for the regulated events).

Regulated Events are NRC regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

Integral Attachments are attachments that are welded to or fabricated as an integral part of the component itself. ASME Section XI focuses on Integrally Welded Attachments (e.g., Examination Category C-D)

Applicable Aging Effects are aging effects that are (1) plausible for a given material, environment, and stress combination, and, (2) if undetected, could result in the loss of the component intended function such that the intended function(s) could not be assured in the period of extended operation.

Class 1 mechanical components include those mechanical components within the ASME Section XI, Subsection IWB, Class 1 ISI boundary. The Class 1 ISI boundary varies from plant-to-plant and includes components within the reactor coolant pressure boundary (RCPB), as defined in 10CFR50.2.

Non-Class 1 mechanical components include those mechanical components that are not within the Class 1 ISI boundary. It should be noted that the Class 1 ISI is not necessarily the same as the reactor coolant pressure boundary; that is, non-Class 1 mechanical components may be found within the reactor coolant pressure boundary at many of the participating utilities (e.g., instrument lines, and tubing downstream of isolation valves or flow restricting orifices).

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1. INTRODUCTION

The Mechanical Tools, which are discussed in Section 3.0 and are contained within the appendices of this document, deal exclusively with non-Class 1 mechanical components subject to an aging management review for license renewal. Due to the similarity of materials and operating environments, the Mechanical Tools are presented as a set of material and environment based rules that will be used by each utility to identify locations where aging effects (e.g., cracking, loss of material, reduction in fracture toughness, distortion, and loss of mechanical closure integrity) may be applicable. For license renewal, utilities must review existing programs to ensure that the identified aging effects are managed so that system and component intended function(s) are assured in the period of extended operation. Based on the possibility that these aging effects could be occurring now, this guideline can also be used by plant engineers to identify plant equipment beyond the license renewal scope that may require aging management attention.

The process by which utilities will identify SCs subject to an aging management review is plant-specific and is discussed briefly in Section 2.0. In addition, the mechanical components subject to an aging management review are listed in Section 2.0. The determination of applicable aging effects using the Mechanical Tools is discussed in Section 3.0. Programmatic evaluation of applicable aging effects is discussed in Section 4.0; however, the programmatic evaluation is a plant-specific task. The material and environment based Mechanical Tools are contained in Appendices A through E. Other specialized tools for heat exchangers, bolted closures, and fatigue are contained in Appendices F through H.

2. NON-CLASS 1 MECHANICAL SCOPE

The mechanical components addressed within this tool include those outside the Class 1 ASME Section XI, Subsection IWB, ISI boundary and subject to an AMR. It should be noted that the Class 1 ISI boundary is not necessarily the same as the reactor coolant pressure boundary; that is, non-Class 1 mechanical components may be found within the reactor coolant pressure boundary at many plants (e.g., instrument lines, and tubing downstream of isolation valves or flow restricting orifices). The identification of SCs subject to an aging management review is discussed in Section 2.1. A list of mechanical components subject to an aging management review is provided in Section 2.2. Typical materials of construction are discussed in Section 2.3.

2.1 Identification of SCs Subject to an Aging Management Review

For license renewal, applicants must first determine which SSCs are within the scope of license renewal in accordance with the scoping requirement defined in 10 CFR 54.4. The IPA, as defined by 10 CFR 54.21 (a)(1), requires that applicants list those structures and components within the scope of license renewal that are subject to an aging management review. An aging management review must be performed on the identified list in accordance with 10 CFR 54.21 (a)(3).

Documentation of the non-Class 1 mechanical components subject to an aging management review is plant-specific and may be performed on a system-by-system basis utilizing existing system boundary definitions that are consistent with the both the CLB and system intended functions. Component intended functions that support those system functions will also be identified. Each license renewal applicant may establish the evaluation boundary for each system using the guidance provided in NEI-95-10 Industry Guideline for Implementing the Requirements of 10 CFR Part 54-The License Renewal Rule [1].

Once the system evaluation boundary is established, the mechanical components subject to an aging management review within the evaluation boundary may be grouped in accordance with the list of passive mechanical components in Appendix B of NEI 95-10 [1]. Groups of mechanical components may be evaluated collectively within the system or across system boundaries if constructed from similar materials and exposed to similar operating environments. A typical list of mechanical components subject to AMR is provided in Section 2.2. It should be noted that the list provided in Section 2.2 is the starting list of passive mechanical components; additional components may be added to the applicant's list based on plant-specific findings.

2.2 List of Mechanical Components Subject to AMR

Within each system in the scope of license renewal, the passive mechanical components subject to an aging management review may be identified using the passive mechanical components listed in Appendix B of NEI 95-10 [1] as guidance; this set of reviewable components is discussed in Sections 2.2.1 through 2.2.6. The component function to be evaluated for mechanical components is pressure boundary integrity. Pressure boundary integrity, as used in the mechanical tools, includes both the pressure boundary function and structural integrity function of the component.

Pressure boundary integrity applies to components that operate above and below atmospheric pressure. In all instances, the pressure boundary portions of the non-Class 1 mechanical components are defined by applicable design codes. For example, ASME Section III, Classes 2 and 3, ASME Section VIII, Divisions 1 and 2, AWWA, USAS B31.7 (Classes II and III), and USAS B31.1.0. Many of the mechanical components within the scope of license renewal contain gaskets, packing, and seals that contribute to pressure boundary integrity.

Gaskets, packing, and seals are within the scope of license renewal but may be excluded from aging management review if they are short lived or are replaced based on performance or condition monitoring. From the license renewal rule statement of considerations (SOC) III.f.(b), Long-lived structures and components, "However, the Commission does not intend to preclude a license renewal applicant from providing site-specific justification in a license renewal application that a replacement program on the basis of performance or condition for a passive structure or component provides reasonable assurance that the intended function of the passive structure will be maintained for the period of extended operation." Gaskets, packing, and seals are routinely used as items to remove imperfections in the seating of two material surfaces to prevent leakage. If the two surfaces were perfectly matched, gaskets, packing, and seals theoretically would not be required. Vendors recommend that gaskets, packing, and seals be replaced when leakage is observed, when the joint is opened, or at the end of the qualified life or a specified period of time. Therefore, gaskets, packing, and seals within the scope of license renewal are not subject to an aging management review provided the evaluator can demonstrate that these items are replaced upon performance or condition monitoring, or are replaced on qualified life or specified period of time. These Mechanical Tools assume that the Owner has a replacement program for these components; these components are not included in the scope of this document.

2.2.1 Heat Exchangers

Pressure retaining items of heat exchangers are provided below.

- Shell
- Tubes
- Coils
- Nozzles
- Tubesheets
- Manways
- Handholes
- Bolting
- End Flange
- Water Box (includes Channel Head, End Bell and Flanges)
- Integral Attachments

The component intended functions include pressure boundaries (both shell and tube side) and heat transfer. Additional component information can be found in the Sandia AMG (Reference 4).

2.2.2 Tanks/Vessels

Tanks are normally divided into atmospheric and sub-atmospheric applications. Vessels are typically operated above atmospheric pressure. Tanks within the scope of license renewal are generally located at or above grade; however, they may be located below grade. Pressure retaining items of tanks and vessels are provided below.

- Nozzles
- Bolted Flange and Studded Connections
- Manhole Cover Plates
- Welded Joints and Weld Build-Up
- Integral Attachments
- Plates and Shells
- Domes and Heads

2.2.3 Pumps

The pressure retaining items of pumps within the scope of license renewal include:

- Pump Casings
- Pump Inlets and Outlets
- Pump Covers

- Clamping Rings
- Seal Housings, Seal Glands, and Packing Glands
- Related Bolting
- Welded Joints
- Integral Attachments

2.2.4 Valves

Pressure retaining portions of valves are subject to aging management review. For valves other than pressure relief valves (e.g., globe, check, gate, etc.), the pressure boundary items include the body, welded joints in the body (if applicable), bonnet (if applicable), and associated body-to-bonnet bolting (if applicable). Valve disks and stems are not subject to aging management review since they perform an active function and are functionally tested [2].

The pressure retaining items of pressure relief valves defined in ASME Section III include the bonnet, nozzle, body-to-bonnet joint, disk, spring washer, valve stem, adjusting screw, and spring. However, as described in Reference 2, the disk, valve stem, adjusting screw, and spring washer are not subject to review since these assemblies contain moving parts that contribute to the active function of the valve. The following relief valve pressure boundary items are subject to an aging management review: bonnet, body, associated welded joints (if applicable), and body-to-bonnet bolting.

2.2.5 Piping, Tubing, Fittings, and Branch Connections

The scope includes all pipe, fittings, tubing, branch connections, headers, flanges, integral attachments, bolting, and welded joints that connect these items to other mechanical components.

2.2.6 Miscellaneous Process Components

Miscellaneous process components subject to an aging management review are summarized below.

- Filters--shell, flanged connections, bolting, manway, and housing
- Demineralizers--shell, nozzles, bolting, manway, and housing (consider as vessel)
- Strainers--shell, nozzles, and bolting
- Flex Hose--end flanges, bolting, body, bellows (flex)
- Expansion Joint--end flanges, bolting, body, and bellows
- Spray Nozzles--body, diffuser
- Spargers--pipe and nozzles
- Flex Coupling--flanges and bolting
- Air Ejectors--nozzles, bolting, venturi, and body
- Traps--body, nozzles, and bolting
- Flow Orifice--bolting and body

- In-Line Flowmeter--shell, bolting, and sight glass
- Venturi--shell and bolting
- Flow Restrictor--shell, flanges, and bolting
- Cyclone Separator (pressure boundary)
- Pipe Bellows (pressure boundary)
- Integral Attachments

2.3 Materials of Construction

Common materials used in the fabrication of the components listed above include carbon steel, low-alloy steel, nickel-base alloys, cast iron, copper alloys and various types of stainless steels (e.g., austenitic stainless steels and cast austenitic stainless steels). Typical material types used to fabricate piping are summarized in Table 2-1. Table 3-1 of Reference 3 provides a summary of typical materials used for pressure boundary portions of pumps, and Table 3-3 of Reference 4 provides typical materials of construction for heat exchangers. It is recommended that the evaluator use the handbook entitled "Metals & Alloys in the UNIFIED NUMBERING SYSTEM" published by the Society of Automotive Engineers to identify material types (e.g., A312 Type 304). However, in many instances, detailed material specifications may not be required to identify applicable aging effects.

Table 2-1 Typical Materials of Construction - Piping				
Component Item	***Treated Water***	***Raw Water***	***Air/Gas***	***Fuel/Oil***
Pipe	(stainless steel) A 312 Tp 304,316 A 376 Tp 304,304L,316, 316L A 358 Tp 304,316 A 430 FP304 (carbon steel) A 106 Grade A,B A 53 Grade A,B A 134 A 155, Grade C55, Class1 A 155, Grade KC70, Class1,2 A 672, Gr.C70	(carbon steel) A 106 Grade B, C A 53 Grade B A 134 API 5L, Grade B (stainless steel) A 312 Tp 304,316,316L SA 376 Tp 304,304L,316	(carbon steel) A 106 Grade B A 53, Grade B A 134 A 155, Gr KC70, Class1 API 5L, Gr B (stainless steel) A 312 Tp304 A 376 Tp 304 ASTM 358, Class 1, Gr304	(carbon steel) A 106 Grade B A 53 Grade B A 134 API 5L, Grade B
Fittings	(stainless steel) A 403 WP 304,316,304W A 182 F 304, 316 (carbon steel) A 234 WPB,WPC A 105 Grade I or II A 216 Grade WPB,WCA, WCB	(carbon steel) A 234 WPB A 105 (stainless steel) A 403 WP304 A 182 F304	(carbon steel) A 234 WPB, WPC A 105 (stainless steel) A403 WP304 A182 F304	(carbon steel) A 234 WPB A 105 Grade I or II
Flanges	(stainless steel) A 182 F304,F316 (carbon steel) A 105 Grade II A 181 Grade I or II	(carbon steel) A105 (stainless steel) A 182 F 304	(carbon steel) A105 A 181, Grade 1 (stainless steel) A 182 F316 A 182, F304	(carbon steel) A 181 Grade I or II A105

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3. MECHANICAL TOOLS--APPLICABLE AGING EFFECTS

The aging effects to consider for non-Class 1 mechanical components subject to an aging management review include cracking (initiation and growth), reduction of fracture toughness, loss of material, distortion, and loss of mechanical closure integrity. These aging effects are consistent with aging effects identified in the B&WOG RCS Piping Report (BAW-2243A), Reference 2, and the Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants (Working Draft-September 1997). The purpose of the Mechanical Tools is to assist the evaluator in the identification of locations within system evaluation boundaries where aging effects may be a concern for the period of extended operation. A discussion of each tool is provided in Section 3.1, and the requirements for implementation of the tools are discussed in Section 3.2.

3.1 Development of Mechanical Tools

Applicable aging effects may be determined based upon consideration of materials of construction, operating environment, and stress. In most instances aging effects may be assessed irrespective of the component type being evaluated. Specifically, different component types constructed from the same material and located in the same environment will experience similar aging effects. In addition, the states of stress (residual or operating) in the mechanical components are typically not known. It is assumed that operating stresses are within code allowable in accordance with design requirements, but the component may contain high residual stresses due to fabrication, field installation, and field welding. This approach results in a conservative set of material and environment-based rules when assessing applicable aging effects.

To facilitate the component evaluation process, mechanical systems within the scope of license renewal may be grouped within the following internal environments: treated water, raw water, lube and fuel oil, and gas. Mechanical Tools, which include a set of material and environment based rules to determine aging effects, are prepared for each internal environment as discussed in Sections 3.1.1 through 3.1.4. A separate Mechanical Tool was developed to address degradation of external surfaces of mechanical components since external environments, in some instances, can cause loss of material and/or cracking. The External Tool is discussed in Section 3.1.5.

A tool was prepared to identify aging effects for bolted closures. As discussed above, gaskets are not subject to aging management review provided the evaluator can demonstrate that they are replaced on performance or condition, or are replaced on a qualified life or specified period of time. The remaining portions of the bolted closure, i.e., mating surface and associated bolts, studs, nuts, washers, and bushings, are subject to aging management review. The bolted closure tool is discussed in Section 3.1.6.

In addition to the environment based tools discussed above, a component tool was prepared for heat exchangers since they typically are exposed to multiple environments, e.g., shell side exposed to raw water and tube side exposed to borated water. The heat exchanger tool makes extensive use of the Heat Exchanger AMG prepared by Sandia National Laboratories [4] and is discussed in Section 3.1.7.

Fatigue evaluations for non-Class 1 mechanical components are addressed in the Fatigue Tool. This tool may eventually be integrated with the other tools. At present, the Fatigue Tool addresses thermal fatigue induced cracking of mechanical components in accordance with the TLAA requirements of the IPA and is discussed in Section 3.1.8.

The Mechanical Tools represent a set of rules that allow the evaluator to identify aging effects for a given material and environment. The material and environment based rules are derived from known age-related degradation mechanisms and operating experience such as NPRDS and NRC generic communications. In the development of the environment based rules, the states of stress in the mechanical components are typically not known. It is assumed that mechanical components contain residual stresses due to fabrication, field installation, and field welding.

In addition, it is acknowledged that fabrication flaws, which were within acceptable limits of the design code, may exist in the base metal and/or weld metal of non-Class 1 mechanical components. However, fabrication flaw growth is managed by the inspection requirements for Class 2 components in accordance with ASME Section XI, Subsection IWC, and for Class 3 components in accordance with ASME Section XI, Subsection IWD. Fabrication flaw growth within components that are not Class 2 or 3 is not a concern for the period of extended operation since these components are typically not subjected to operating conditions that could result in a defect.

3.1.1 Treated Water (Appendix A)

All treated water for clean systems starts as demineralized water. Treated water can be further processed: deionized, deaerated, include corrosion inhibitors, biocides, and boric acid, or include some combinations of these treatments. At present, the Treated Water Tool addresses the following environments: borated water, feedwater, main steam (including two-phased fluid), domestic water, intermediate cooling water, and emergency feedwater. Aging effects for materials typically found in these environments are summarized in each of the separate sections of the Treated Water Tool in Appendix A.

Typical systems that contain treated water in PWR plants include High Pressure Injection, Low Pressure Injection/Decay Heat Removal, Core Flood, Reactor Building Spray, Makeup and Purification, Chemical Addition, Spent Fuel Cooling, Condensate, Emergency Feedwater, Main Steam/Feed, Diesel Jacket Cooling, and Intermediate Cooling.

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Typical systems that contain treated water in BWR plants include Main Steam, Feedwater, Condensate, Reactor Core Isolation Cooling, RHR/Low Pressure Injection, High Pressure Coolant Injection, Low Pressure Core Spray, High Pressure Core Spray, Standby Liquid Control, Containment Spray, Reactor Building Closed Cooling Water, Isolation Condenser, Nuclear Steam Supply Shutoff, Reactor Pressure Relief, Condensate Storage, Containment Atmospheric Cooling, and Fuel Pool Cooling and Cleanup.

3.1.2 Raw Water (Appendix B)

Raw water is defined as water that enters a plant from a river, lake, pond, well, ocean, or bay which has not been demineralized. In general, the water has been rough-filtered to remove large particles and may contain a biocidal additive for control of micro-organisms, zebra mussels, and asiatic clams. Sodium chloride content is below 1000 mg/l for fresh water, above that for brackish water and saltwater. Raw water is typically used for the condenser circulating water system and the nuclear grade service water system. Typical materials used in these systems include stainless steel, carbon steel, copper/nickel alloys, cast iron, aluminum bronze, galvanized steel, and titanium. Aging effects for materials typically found in these environments are summarized in Appendix B.

Typical systems that contain raw water in PWR plants include Low Pressure Service Water, High Pressure Service Water, Auxiliary Service Water, Reactor Building Cooling, Condenser Circulating Water, and Fire Protection.

Typical systems that contain raw water in BWR plants include Essential Service Water, Diesel Cooling Water, Circulating Water, High Pressure Core Spray Emergency Power Cooling Water, Emergency Service Water Spray Pond, Emergency Service Water, RHR Service Water, Service Water, and Fire Protection.

3.1.3 Oil and Fuel Oil (Appendix C)

Fuel Oil:
Diesel oil, no. 2 oil or other liquid hydrocarbons used to fuel diesel engines [3]. Fuel oil may be treated with a biocide.

Lubricating Oil:
Low to medium viscosity hydrocarbons used for bearing, gear, and engine lubricating [3].

Typical systems that contain oil and/or fuel oil in PWR plants include the Diesel (lube oil and fuel oil), Safe Shutdown Diesel (lube oil and fuel oil), and Station Blackouts Diesel (lube oil and fuel oil).

Typical systems that contain oil and/or fuel oil at BWR plants include Emergency Power Diesel Fuel Oil, High Pressure Core Spray Diesel Fuel Oil, Emergency Diesel Lube Oil, High Pressure Core Spray Diesel Lube Oil, Lube Oil, and Hydrogen Seal Oil.

3.1.4 Gas (Appendix D)

The gas environments within the scope of license renewal include atmospheric air, ventilation (filtered and unfiltered), instrument air (clean and dry), and compressed gases (CO_2, H_2, Halon, and nitrogen).

Typical systems that contain a gas environment in PWR plants include Breathing Air, Chemical Addition, Gaseous Waste, Instrument Air, Leak Rate, Nitrogen Purge and Blanket, Reactor Building Cooling, Penetration Room Ventilation, Reactor Building Purge, Vacuum, Diesel Air Intake and Exhaust, and Diesel Air Start.

Typical systems that contain a gas environment in BWR plants include H_2/O_2 Analyzers, Standby Gas Treatment, Secondary Containment, Combustible Gas Control, Emergency Diesel Starting Air, Off Gas Holdup, Off Gas Recombiner, Instrument Air, Alternate SRV Nitrogen Supply, Hydrogen Cooling, Diesel Generator Building HVAC, Emergency Service Water Pumphouse Ventilation, and Safety Related Chilled Water.

3.1.5 External Environments (Appendix E)

The external tool addresses degradation of the external surfaces of the components listed in Section 2.0 (with the exception of bolted closures) for various environmental conditions. Degradation of external surfaces of bolted closures is addressed in Appendix F.

3.1.6 Bolted Closures (Appendix F)

Bolting applications within the scope of license renewal may be divided into pressure boundary bolting and structural and component support bolting. Pressure boundary bolting applications, which are addressed in Appendix F, include bolted flange connections for vessels (i.e., manways and hand holes), flanged joints in piping, body-to-bonnet joints in valves, and pressure retaining bolting associated with pumps and miscellaneous process components; these bolted joints are hereafter referred to as bolted closures. Structural and component support bolting is not addressed in Appendix F. A bolted closure includes the entire bolted joint, e.g., seating surfaces (e.g., flange set surfaces), gasket, and pressure retaining bolting. Aging management programs required to assure bolted closure integrity will be addressed on a plant-specific basis using general recommendations provided in Section 4.0 of Appendix F.

3.1.7 Heat Exchangers (Appendix G)

Appendix G contains the heat exchanger tool. Extensive use is made of the AMG on heat exchangers [4]; however, in some instances the GLRP found the AMG to be extremely conservative in its evaluation of some age-related degradation mechanisms. Appendix G provides guidance on the use of the AMG for license renewal applications.

The AMG evaluates a specific set of PWR and BWR heat exchangers considered to be within the scope of License Renewal. See Appendix G for a listing of those heat exchangers.

3.1.8 Fatigue (Appendix H)

The non-Class 1 fatigue screening tool provides a logic and methodology by which mechanical systems within the scope of license renewal may be evaluated to determine components susceptible to cracking from thermal fatigue. The Fatigue Tool is discussed in Appendix H.

3.2 Implementation of Mechanical Tools

When evaluating structures and components within a system, determine the boundary of the system in accordance with the current licensing basis (CLB) and the defined system intended functions. Evaluation boundaries may be established using intended system functions in combination with documents such as P&IDs, System Descriptions, and Design Basis Documents. The evaluator must determine the operating modes of the system. Operating mode data should include chemistry specifications, operating pressures, operating temperatures, and system flowrates for all modes of operation. Assessment of current data and projection of operating mode data into the period of extended operation is recommended. The operating mode data define the environment and stress that contribute to the aging of the mechanical equipment within the system.

The normal aging environment and stresses that the components experience should be evaluated; this includes conditions observed during normal and upset conditions (e.g., ASME Service Level A&B). Emergency and faulted conditions (e.g., ASME Service Level C&D) do not constitute the normal aging environment and stresses for the mechanical components, and the determination of applicable aging effects should not be based on these conditions. As discussed in Section 3.0 of Reference 2, aging management for component aging effect combinations that result from regularly experienced conditions (i.e., normal and upset conditions) will ensure that the components can maintain their design requirements in the period of extended operation. Each operating mode should be evaluated using the tools contained in the appendices to determine the full set of applicable aging effects.

When using the tools to determine the full set of applicable aging effects, programs credited to preclude aging effects (e.g., water chemistry and protective coatings) must be carried forward as aging management programs. The evaluator must include these programs as aging management programs when demonstrating aging management to provide reasonable assurance that the intended function is maintained. Demonstration of the management of applicable aging effects to ensure the component intended function during the period of extended operation is plant-specific and is addressed in Section 4.0.

4. DEMONSTRATION OF AGING MANAGEMENT

The demonstration of aging management to provide reasonable assurance that the component intended function will be maintained in the period of extended operation will be determined on a plant-specific basis. The Mechanical Tools will be used to identify applicable aging effects that must be managed. Utilities will be responsible for the documentation required to show that aging is managed by existing plant programs and/or additional actions. The documentation is plant-specific. The requirements for demonstrating aging management are discussed in Section 4.1.

4.1 Requirements for Demonstration of Aging Management

The criteria for demonstrating that the effects of aging are managed are presented in Section 4.2.1.3 of NEI 95-10 [1] and are not repeated here. The final safety evaluation report (SER) published by the NRC concerning the RCS Piping Report [2] provides a current example of demonstration of aging management. Future SERs of non-class 1 mechanical component license renewal submittals should be reviewed for examples of acceptable demonstration of aging management. Programs credited for aging management can include regulated programs and commitments to generic communications. Programs that might be credited for aging management include the following:

- ASME Section XI, ISI, IST
- Commitments to Generic Letter 89-13
- Commitments to Generic Letter 89-10
- Commitments to IE Bulletin 79-17
- Commitments to IE Bulletin 89-12
- Commitments to IE Bulletin 88-65
- Erosion/Corrosion Programs
- Boric Acid Leakage Management Programs
- Appendix J Programs
- Programs Credited to Preclude Aging Effects (e.g., chemistry program and protective coatings program)

It is expected that in most instances existing programs will be found to adequately manage the applicable aging effects. However, for instances where existing programs do not fully assure the management of the applicable aging effects, additional actions may be required for license renewal.

4.2 FSAR Supplement

Once completed with each system evaluation, a summary of the program elements and commitments credited for aging management must be prepared. This information will be included in the applicant's FSAR supplement. In addition, commitments for additional actions will be captured in the FSAR supplement.

5. REFERENCES

1. "Industry Guideline for Implementing the Requirements of 10 CFR Part 54- The License Renewal Rule," NEI 95-10, Revision 0, March 1996.

2. G. Robison, E. Grubbs, M. Rinckel, and R. Starkey, "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," BAW-2243A, Framatome Technologies, Inc., Lynchburg, VA, June 1996.

3. "Aging Management Guideline for Commercial Nuclear Power Plants-Pumps," Contractor Report No. SAND93-7045, Sandia National Laboratories, 1994.

4. "Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers," SAND93-7070, prepared by MDC-Ogden Environmental and Energy Services under contract to Sandia National Laboratories for the U.S. Department of Energy, June 1994.

Appendix A--Treated Water

All treated water for clean systems starts as demineralized water. Treated water can be further processed: deionized, deaerated, include corrosion inhibitors, biocides, and boric acid, or include some combinations of these treatments. Treated water may be divided into the following sub-environments: borated water, main feedwater/steam, intermediate or closed cooling water, emergency feedwater, containment spray, core spray, low and high pressure injection, and condensate. Stainless steels are predominantly used in systems containing borated water. The remaining treated water systems may contain stainless steel, carbon steel, cast iron and copper alloys (brass, bronze, copper nickel alloys).

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1. INTRODUCTION

The Treated Water Tool is a methodology that identifies applicable aging effects for materials subjected to a treated water environment. Treated water environments include liquid, steam and two-phase flow. Applicable aging effects include cracking, loss of material, loss of material properties, reduction of fracture toughness, distortion, and loss of mechanical closure integrity. Loss of mechanical closure integrity is not addressed in the Treated Water Tool, but is treated separately in Appendix F. The Treated Water Tool may be applied to the following components: pipe, tubing, fittings, tanks, vessels, valve bodies and bonnets, pump casings, and miscellaneous process components. Aging effects associated with both internal and external environments must be assessed; this tool is restricted to internal environment and material combinations. Aging effects of materials exposed to external environments, such as humid air, are addressed in Appendix E. Evaluation of heat exchangers is performed with the tool contained in Appendix G. Evaluation of fatigue cracking is addressed in Appendix H.

The materials and environments covered in the Treated Water Tool are discussed in Section 2.0. Aging effects that apply to the material and environment combinations are discussed in Section 3.0. The development of the evaluation flowchart is presented in Section 4.0.

2. MATERIAL AND ENVIRONMENT

The Treated Water Tool will assist the evaluator in determining locations within systems containing treated water that may be susceptible to one or more of the following aging effects: cracking, loss of material, reduction of fracture toughness, or distortion. The term "treated water" comprises liquid, steam, and two-phased flow environments. The materials addressed in this tool are discussed in Section 2.1 and the specific material and environment combinations are defined in Section 2.2.

2.1 Materials

The following materials are addressed in this tool: (1) wrought and cast stainless steels (including weld metals and cladding), (2) nickel-based alloys (including nickel-based alloy weld metal), (3) carbon and low alloy steels (including weld metals), (4) cast irons, (5) copper alloys (brass, bronze, copper nickel), and (6) protective coatings (e.g., plasite).

2.1.1 Stainless Steels

The stainless steels are divided into the following categories: (1) wrought stainless steels, (2) cast stainless steels, (3) weld metals, and (4) stainless steel cladding. Each category is discussed below.

Wrought Stainless Steels
Wrought stainless steels comprise five groups: (1) austenitic, (2) ferritic, (3) martensitic, (4) precipitation hardening, and (5) duplex stainless steels. Definitions of the groups of stainless steels are provided in Reference 1 and are not repeated here. From a review of systems that contain treated water within the scope of license renewal, wrought austenitic materials (Type 300 series) are predominantly used for piping, tubing, selected valve bodies and bonnets, and selected tanks and vessels. Ferritic stainless steels are not typically used in treated water systems, and are not evaluated in this tool. Martensitic and precipitation hardening stainless steels are typically used for bolting, valve stems, and pump shafts, and are not evaluated in this tool. [Note: valve stems and pump shafts are not subject to aging management review in accordance with the discussion in Section 2.0 of the main document.] Bolted closures are addressed in Appendix F.

Cast Stainless Steels
The cast stainless steels addressed in the Treated Water Tool all contain ferrite in an austenitic matrix (i.e., CF series) and are commonly known as cast austenitic stainless steel (CASS). Alloys used in nuclear applications include CF-8, CF-8M, CF-3, and CF-3M, which are cast counterparts of wrought Types 304, 316, 304L, and 316L, respectively. Alloys CF-3M and CF-8M are modifications of CF-3 and CF-8 containing 2% to 3% molybdenum and slightly higher nickel to enhance resistance to corrosion and pitting. However, molybdenum enhances long-term thermal embrittlement at operating temperatures greater than 400 °F.

Stainless Steel Weld Metal

The welding materials used to join stainless steels are dependent upon the type of material being joined. For example, Type 304 wrought austenitic stainless steels may be joined using either gas metal-arc welding (GMAW), submerged-arc welding (SAW), or shielded metal-arc welding (SMAW) processes with a Type 308 electrode or welding rod. The various welding processes used to join wrought stainless steels in treated water systems include SMAW, SAW, GMAW, gas tungsten-arc welding (GTAW), and plasma-arc welding (PAW). Flux core arc welding (FCAW) may have been used but to a lesser extent. Cast stainless steel welding processes typically used include SMAW, GTAW, GMAW, and electroslag welding [1].

In general, weld metals are more resistant to cracking by SCC than wrought stainless steel and are more like CASS from that perspective. However, it should be noted that strength and toughness of selected stainless steel weld metals used to join wrought stainless steels were shown to vary depending upon the welding process used [2]. For example, flux welds, such as SAW and SMAW, were shown to provide joint properties with higher strength and significantly lower toughness than the surrounding base metal. Higher strength of the weld metal results in enhanced load bearing capacity compared to base metal; lower toughness of the weld metal may result in a reduced ability to support structural loads if the weld metal cracks. The strength and toughness of nonflux welds, such as GMAW and GTAW, were shown to be similar to the surrounding base metal.

Stainless Steel Cladding Material

Stainless steel cladding exposed to non-Class 1 treated water environments within the scope of license renewal is typically austenitic stainless steel. Cladding may take the form of weld deposit or stainless steel plate that is either explosively applied or rolled onto carbon or low-alloy structural steel. A detailed description of weld deposit cladding is provided in Section 3.0 of Reference 4. The cladding is assumed to be equivalent to the wrought austenitic stainless steels with respect to the discussions of loss of material and resistance to cracking in Section 3.0.

2.1.2 Nickel-Base Alloys

The nickel-base alloys that are typically used for nuclear applications are Alloy 600 and Alloy 690. These materials are used primarily for their oxidation resistance and strength at elevated temperatures. The applications are typically restricted to the reactor coolant system (e.g., reactor vessel CRDM nozzles), but may also be found in selected non-Class 1 components such as the Core Flood Tanks. In addition, Alloy 600 may also be used in fasteners, which are discussed in Appendix F. Other nickel-base alloy materials such as nickel-copper and nickel-copper-molybdenum alloys are not evaluated in this tool.

Welding of nickel-chromium-iron alloys is typically performed using arc-welding processes such as GTAW, SMAW and GMAW [1]. Submerged arc welding may also be used provided the welding flux is carefully selected. Alloy 82 and Alloy 182 are typical filler metals used to join Alloy 600 components to carbon or low-alloy steel vessels. Alloys 82 and 182 are also used as cladding in selected components within the reactor coolant system. In addition, Alloy 52 and Alloy 152 are typical filler metals used to join Alloy 690 components to carbon or alloy steel vessels in the reactor coolant system.

2.1.3 Carbon and Low-Alloy Steel

Carbon steels are unalloyed except for specified amounts of carbon. In addition, carbon steel may contain small amounts of manganese, phosphorus, silicon and sulfur. Carbon steels typically used in non-Class 1 applications include, but are not limited to, ASTM A105 Grade I or II, ASTM A 106 Grade B, ASTM A181, and ASTM A234 Grade WPB. Differentiation between wrought and cast product forms is not required.

Low-alloy steels contain small amounts of alloying elements such as nickel, chromium, molybdenum, and manganese, which enable them to be hardened by quench and temper heat treatment. They are generally used for Class 1 components but may be found in some non-Class 1 applications such as bolting. Typical examples include ASTM A 508 and ASTM A 533. Differentiation between wrought and cast product forms is not required.

In general, carbon and low-alloy (ferritic) steels may be joined using various arc welding processes, for example, FCAW, GMAW, GTAW, PAW, SAW, and SMAW. All weld filler metals used in welding carbon and low-alloy steels are assumed to be equivalent to the carbon and low-alloy base metal with respect to the discussions of loss of material, reduction in fracture toughness, distortion, and resistance to cracking (initiation) in Section 3.0.

2.1.4 Cast Iron and Cast Iron Alloys

The term cast iron is a generic term for a large family of cast ferrous alloys in which the carbon content exceeds the solubility of carbon in austenite at the eutectic temperature [1]. A majority of the cast irons of interest contain a minimum of 2% carbon with sulfur and silicon elements added depending on the specific properties desired. Other alloying elements, such as chromium, copper or nickel, are used where high corrosion resistance, hardness or other mechanical properties are desired. The common forms of cast iron encountered are white cast iron, gray cast iron, malleable cast iron and ductile or nodular cast iron. In many cases the word “cast” is often left out, resulting in “gray iron,” “white iron,” malleable iron,” and “ductile iron” respectively [7].

White Cast Iron

This category of cast iron is so named because of the characteristically white fracture surfaces, which occur due to the lack of any graphite in their microstructures. Carbon is present in the form of carbides. These cast irons are hard, brittle and have high compressive strength with good retention of strength and hardness at elevated temperatures. The hardness of this form of iron results in a high resistance to wear and abrasion; therefore, these irons are used primarily where there is a need for resistance to wear and abrasion [1].

Gray Cast Iron

This form of cast iron is the most common of the iron alloys in nuclear plants. It is most commonly found in raw water systems (particularly in fire suppression water systems) although some treated water applications may exist. In these iron alloys, the carbon is above the solubility limit of austenite at the eutectic temperature [1]. During cooling and solidification, a substantial portion of the carbon content separates out of the liquid and forms flakes of graphite. This material is usually selected because of the relatively low cost and ease of machining and excellent resistance to wear [7]. Another attribute of this material is its ability to be cast in thin sections. Gray cast iron alloys also contain outstanding properties for applications involving vibrational damping or moderate thermal shock.

Ductile Cast Iron

Ductile cast iron is commonly known as nodular or spheroidal-graphite iron. It is similar to gray iron but with the addition of small amounts of magnesium and/or cerium added to the molten iron in a process called nodulizing. The resultant graphite grows as tiny spheres rather than the flakes in gray iron due to these additives. The major advantages that these ductile cast irons exhibit when compared to gray iron are a combination of high strength and ductility, which results from the graphite spheres [1,7]. Nickel, chromium and/or copper can be added to improve material strength and hardenability properties. Larger amounts of silicon, chromium, nickel or copper can also be added for improved resistance to corrosion or for high-temperature applications [7].

Malleable Irons

Malleable iron is white cast iron that is heat treated to form graphite clusters instead of flakes thus increasing the ductility of the material. Malleable iron and ductile iron are used in similar applications where ductility and toughness are required, when cost and availability are the primary selection criteria.

Compacted Graphite Cast Iron

This type of cast iron is manufactured by very carefully controlling the amount of magnesium added as an inoculant in a process very similar to the process used to make ductile iron. Impact and fatigue properties, although not as good as ductile iron, are substantially better than those of gray cast iron. The combination of high strength and good impact resistance, coupled with a good capacity for heat dissipation makes CG irons well suited for applications where neither gray nor ductile iron is entirely satisfactory [1].

Alloy Cast Irons

Various alloying elements can be added to cast iron to improve corrosion and abrasion resistance, heat resistance, and mechanical properties. However these alloys are not widely used in the nuclear industry. The main advantage of using cast iron is the relatively low cost and abundance. When special material properties are required, it is likely that other materials would be used. A discussion of some of the most common cast iron alloys is included to provide insight for the occasional application that may be encountered during plant evaluations.

The most common alloying elements are silicon, chromium, nickel and copper [1,7]. High silicon irons are the most universally corrosion-resistant alloys available at moderate cost. All cast irons contain up to 3% silicon. Alloys containing 4.5% to 8.0% silicon have been shown to demonstrate excellent high temperature properties, while a silicon content above 14% yields an alloy that is extremely resistant to corrosion, particularly in acidic environments [7]. Corrosion resistance can be increased in white, gray, or nodular iron by adding nickel, chromium and copper (or a combination thereof) or silicon in excess of 3% [1]. These alloying elements promote the formation of a strongly protective surface film under oxidizing conditions (such as exposure to acids). High nickel alloys containing greater than 12% nickel provide excellent resistance to corrosion and heat. (These high nickel alloys also contain 1 to 6% chromium and as much as 10% copper which enhance corrosion resistant properties). The addition of copper results in better resistance to sulfuric acid and atmospheric corrosion. The high abrasion resistance and excellent corrosion resistance of high chromium white irons have resulted in the development of a several alloys containing 20 to 35% Chromium [1].

These iron alloys as described above are but a few of the many diverse iron alloys available. However, due to the specialized nature of the alloys, the availability and the cost, they have a very limited application at most plants. Descriptions are included above to provide guidance where this limited application is identified.

2.1.5 Copper Alloys

Copper metals resist the atmosphere, fresh and salt waters, alkaline solutions (except those containing ammonia) and many organic chemicals. The resistance to corrosion by oxidizing acids depends mainly on the severity of oxidizing conditions in the acid solution. Copper metals are suitable for use with many salt solutions. Although copper based alloys generally have high corrosion resistance, copper and brass, partially due to the relative softness of the material, are very susceptible to erosion corrosion [7]. Bronzes, aluminum brass alloys, and copper nickel alloys containing a small amount of iron demonstrate greater erosion corrosion resistance than other copper alloys [7].

Brass and bronze products are available in both cast and wrought product forms with most alloy compositions available in both. Brasses and bronzes containing tin and lead and/or zinc have only moderate tensile and yield strengths and high elongation. Aluminum bronzes, manganese bronzes and silicon brasses/bronzes are used where higher strength alloys are required. Although copper alloys have wide use in heat exchangers, their use in some applications is restricted as a result of the loss of strength and the susceptibility to creep at moderately elevated temperatures [1]. Copper nickel alloys do not experience these effects under such conditions and can be used where elevated temperatures are encountered.

Because of the large number of copper alloys available and the wide range of mechanical properties exhibited by some of these specialty materials, it is not possible to include this entire spectrum in the tool logic. This Appendix addresses the most common copper alloys that are present in treated water systems at both BWR and PWR plants. The copper alloys included in the tool logic are; (1) Yellow Brass, (2) Commercial Bronze, (3) Muntz Metal (60 - 40% Cu. Ni.), and (4) Copper Nickel alloys (both 90-10 and 70-30 Cu. - Ni.). Although the focus is on these alloys, other alloys such as aluminum bronze and silicon bronze have been included where significant aging effects were identified.

Brass, bronze, muntz metal and copper nickel result from the addition of other metals (such as tin, zinc or nickel) to the base copper material. Most brasses and muntz metal have zinc and other elements added to increase corrosion resistance or optimize material properties. Bronze generally is an alloy of copper and tin. The most commonly used bronze is commercial bronze-- a copper/zinc alloy. Various other elements such as aluminum, silicon, lead, etc., are used with copper to produce aluminum bronze, silicon bronze, lead bronze, etc. Cupronickel is an alloy containing copper and nickel.

Copper and its alloys generally exhibit very high resistance to corrosion in the environments covered by this treated water tool. Copper does, however, react with sulfur or sulfides to form copper sulfide and should not be used in environments where these contaminants will be present [7]. As in all materials, copper and its alloys are susceptible to various forms of aging effects under certain conditions. Crevice corrosion and pitting corrosion are generally applicable to all materials under certain conditions and the copper alloys are no exception. The following discussions include identification of the specific degradation mechanisms for the various copper alloys.

Yellow Brass

Yellow Brass, sometimes referred to as cartridge brass, is a 70% Cu and 30% Zn alloy with relatively low yield and tensile strength [1, 7]. Although it is typically used in raw water systems because of its corrosion resistance, it does have limited use in the many treated water systems covered by this tool. Yellow brass is susceptible to both stress corrosion cracking and selective leaching under certain environmental and fluid conditions as are most copper alloys with greater than 15% Zn content [1,7].

Commercial Bronze

Commercial Bronze is a copper-zinc alloy containing 90% Cu and 10% Zn. It is commonly in raw water systems where higher resistance to corrosion is necessary. However, it is also used in limited treated water applications. The strength and hardness is higher than brass and this material is used where increased resistance to erosion-corrosion and impingement attack is required. The lower zinc content of this material provides high resistance to stress corrosion cracking and selective leaching, although the low zinc content makes the material more susceptible to pitting and crevice corrosion in a stagnant or low flowing environment [1,7].

Muntz Metal
Muntz metal is a copper-zinc alloy containing 60% Cu and 40% Zn. This material has high thermal conductivity, corrosion resistance and machinability and is used primarily for heat exchanger tube sheets. The high zinc content makes this material susceptible to stress corrosion cracking and selective leaching [1,7]. Erosion corrosion is also a concern for this material when subjected to relatively high velocities.

Naval Brass
Naval brass is a copper zinc alloy resulting from the addition of Sn. to the basic composition of Muntz metal. The result is an inhibited alloy containing 60% Cu, 40% Zn and 0.75% Sn.

Copper Nickel
The majority of copper nickel alloys used in treated water systems in BWRs and PWRs are the 90 - 10% and 70 - 30% copper nickel combinations. These materials are primarily used as heat exchanger tube material. (Appendix G of these Mechanical Tools addresses heat exchanger applications in greater detail.) Of all the copper alloys, cupronickel provides the greatest overall resistance to general corrosion and is highly resistant to stress corrosion cracking and erosion corrosion [1,7]. Pitting and crevice corrosion are a concern for copper nickel alloys in an aqueous environment.

2.1.6 Protective Coatings

Some of the carbon steel vessels and tanks within the scope of license renewal contain organic protective inner coatings. For example, Plasite is used as an internal coating material for the Borated Water Storage Tanks at some B&W plants. Plasite is manufactured by Wisconsin Protective Coating Corporation and is a water resistant phenolic coating cross linked with epoxy resin and polymerized with an alkaline type curing agent. Other carbon /low alloy steel and cast iron applications, mostly in raw water environments, also can be coated or lined. Metallic underground piping containing salt or brackish water is often concrete lined to provide corrosion protection. Organic based coatings such as coal tar are used in moderately corrosive environments to provide protection for the base metal. This type of coating is common where cast iron is the base metal and raw water is the environment.

Organic Inner Coatings
Cured organic coatings, such as phenolic-resin films, are among the most resistant to water, acids, alkalis, and solvents of all types that are available. Phenolic-resin coatings have over 30 years of excellent field history as a lining for tanks containing deionized water with temperatures of 180F to 190F. For example, a Technical Bulletin for Plasite 7155 [6] contains results of a test in a boric acid solution consisting of 1”x5” mild steel test panels coated with a film thickness of 8 to 10 mils. The panels were half immersed

in a 25% boric acid solution for a period of six months with no effect on the coating. Blistering and delamination of organic coatings have been reported (Section 3.5); however, root cause evaluations indicate that the failures were attributed to improper installation and insufficient curing following application of the coating. At present, there are no reported or known aging degradation mechanisms of organic linings exposed to treated water environments that could lead to loss of material, cracking, reduction of toughness, or distortion assuming the coating was applied in accordance with the manufacturers requirements.

Aging degradation of organic coatings may not be a concern, however, as noted previous, failures of coatings have occurred (albeit not specifically in treated water systems). These failures are not necessarily related to aging of the coating. Failures are often caused by poor original installation as noted in the generic correspondence evaluation for IN 85-024 included in Section 3.5 of this Appendix. The concern resulting from failure of the liner/coating is the effect on the underlying base material as it contacts the fluid environment. Whether the failure results from improper maintenance, inadequate installation or other cause is not important if it does not result in failure of the base metal pressure boundary function. Since failures have been identified in linings/coatings, it is incumbent on each plant to assess the adequacy of those linings/coatings credited with preventing degradation of the base material.

Not all types of coatings and applications can be included in this mechanical tool logic because of the various types of coatings and the diverse range of applications and environments encountered. This tool allows each utility to credit these various coatings and linings as a means of preventing or minimizing aging effects which would otherwise result from contact of the base metal with the fluid environment. However, if crediting the various linings and coatings with aging effects management, a key requirement of such an approach is the continued assurance of the lining/coating integrity. This tool requires verification of the liner/coating integrity if credit for such a design feature is taken. Where various plant programs or inspections are credited with assuring the lining/coating integrity, any such programs should be continued through the license renewal period and included as license renewal "effective programs."

External protective coatings are not addressed in this tool since external surfaces are covered in Appendix E.

2.1.7 Cathodic Protection

Cathodic protection is an electrochemical means of corrosion control. A galvanic cell is purposely created where corrosion is suppresses at the cathode and oxidation is concentrated at the anode. For example, where a buried steel pipeline (cathode) is electrically connected to sacrificial magnesium the oxidation is concentrated at the magnesium, thus significantly reducing the corrosion of the pipeline. This tool allows each utility to credit cathodic protection as a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the fluid environment. This tool requires monitoring and inspection of cathodic protection systems if credit for such a device is taken. Where various plant programs or inspections are credited with assuring the integrity of a cathodic protection system, any such programs should be continued through the license renewal period and included as license renewal "effective programs."

2.2 Environment

All treated water for clean systems starts as demineralized water. Treated water can be further processed (deionized, deaerated) or include corrosion inhibitors, biocides, and boric acid, or include some combinations of these treatments. Treated water is divided into two categories: borated and non-borated.

PWR systems constructed from stainless steel that contain borated water include ECCS systems (i.e., HPI, LPI, and Core Flood), chemical addition system, spent fuel cooling system, reactor building spray system, and the makeup and letdown systems. Water chemistry requirements for the PWR reactor coolant system are provided in the EPRI Water Chemistry Guidelines [3] for all modes of operation. Appendix B of Reference 3 provides recommendations for chemistry control of the makeup and letdown systems, boric acid storage tank, borated water (refueling water) storage tank, and spent fuel cooling system. The control parameters for PWR systems containing borated water (e.g., ECCS) are, in general, similar to those of the PWR Reactor Coolant System with the exception of dissolved oxygen levels. Portions of the high and low pressure injection systems and the reactor building spray system take suction from the borated water storage tank which is not deaerated; similarly, the spent fuel cooling system water is exposed to the environment and is not scavenged for oxygen. Typically, makeup water for these systems comes from a demineralized water source (see Table 2-2 below) and the chemical addition system for boric acid adjustment.

The only BWR system containing borated water is the Standby Liquid Control System. This system typically uses sodium pentaborate as a source of boron, as opposed to the boric acid used in the PWR systems. The Standby Liquid Control System uses a 15 to 19.6 wt% solution of sodium pentaborate, which is relatively benign to the stainless steel in the system.

Some of the PWR systems that contain non-borated treated water include main feedwater, main steam, intermediate or closed cooling systems, makeup water, and emergency feedwater.

Similar BWR systems that contain non-borated treated water include containment spray, high and low pressure core spray, high and low pressure coolant injection, RHR, condensate, feedwater, main steam, reactor core isolation cooling, reactor building closed cooling water, isolation condenser, nuclear steam supply shutoff, and control rod drive hydraulic systems. BWR components in the power production loop (condensate, feedwater, and main steam systems) contain water or steam resulting from Normal Water

Chemistry (NWC) or Hydrogen Water Chemistry (HWC) to protect the reactor internals and primary recirculation components. The environment in these systems is considered a special case of treated water for the purpose of this tool and is discussed in the following sub-sections.

The following tables present recommended water chemistry [3], [13], or [30]. They are included as generic information only, however, these chemistry limits were consulted when preparing the tool logic provided in Chapter 4 of this document. Each plant should compare specific chemistry limits when implementing this tool to verify all assumptions included in the logic.

Table 2-1 PWR Feedwater/Main Steam Water Chemistry

PARAMETER	NORMAL POWER OPERATION	STARTUP	HOT STANDBY	STEAMING AT <15% FULL POWER
pH @ 77F	(a)	(a)	(a)	(a)
Hydrazine, ppb	≥20	≥20	≥20	≥20
Dissolved Oxygen, ppb	≤5	≤100	≤10	≤5
Sodium, ppb	≤3	---	---	---
Chloride, ppb	≤5	---	---	---
Corrected[b] Conductivity, μS/cm @ 77F	≤0.2	≤1.0	<0.5	<0.5
Silica, ppb	≤20	≤20	≤20	≤20
Total Iron, ppb	<10	≤100	≤10	≤10
Suspended Solids, ppb	<10	---	---	---
Copper, ppb	<2	---	---	---
Sulfate, ppb	<10	---	---	---

[A] Dependent on site specific amine program being used.
[b] Corrected for organic acids or substitution of calculated value based on sulfate and chloride content.

Table 2-2 PWR Makeup Water Chemistry

PARAMETER	SYSTEM EFFLUENT OR STORAGE TANK
Conductivity, μS/cm @ 77F	≤1.0
pH @ 77F	6.0 - 8.0
Chloride, ppm	≤0.1
Fluoride, ppm	≤0.1
Sulfate, ppm	≤0.05
*Active Silica, ppm	<0.10
*Aluminum, ppm	<0.08
*Magnesium, ppm	<0.04
*Calcium + Magnesium, ppm	<0.08

- Diagnostic Parameters per EPRI Primary System Guidelines, NP-7077, [3].

Table 2-3 PWR Auxiliary Feedwater Water Chemistry

PARAMETER	CONCENTRATION
pH @ 77F	(a)
Dissolved Oxygen, ppb OTSG ≤ 250F	Maintain hydrazine at >3×(O_2) @ STP
Dissolved Oxygen, ppb OTSG ≥ 250F	≤10
Hydrazine, ppb	≥3×(O_2)
Conductivity, μS/cm @ 77F	≤1.0

[a] Dependent on site-specific amine program.

Table 2-4 PWR Intermediate Cooling Water Chemistry

PARAMETER	CONCENTRATION
*pH @ 77F	≈10.0
*Dissolved Solids (including additives), ppm	≤2,000
Chloride, ppm	≤1.0
Fluoride, ppm	≤1.0
*Phosphate as Phosphate, ppm	100 - 300
*Chromate as Chromate, ppm	300 - 500

* FTI main recommended treatment. Systems using other chemical control additives will have different control parameters.

Water chemistry of the main feedwater/steam system is closely monitored to minimize the potential for degradation of the Once-Through Steam Generators (OTSGs). The addition of amines to control the pH of feedwater is maintained by the addition of amines to minimizes iron transport, thereby reducing the potential for flow assisted corrosion . The dissolved oxygen level is maintained by either deaeration or with the addition of hydrazine. Impurities such as chlorides and sulfates are controlled to prevent SCC of OTSG tubes.

The chemistry requirements for the demineralized or makeup water are stringent since this water is used for reactor coolant, secondary, and other auxiliary systems where high quality water is required.

Emergency feedwater systems have strict requirements for dissolved oxygen; however, it is noted that not many plants have an oxygen controlled condensate storage tank, which is the suction source for the emergency or auxiliary feedwater system. The chemistry in the closed or intermediate cooling water systems can vary considerably because of the different chemical control additives used at each site.

Table 2-5 BWR Feedwater/Condensate

PARAMETER	NORMAL POWER OP >10% POWER	STARTUP/HOT STANDBY (≥200F to <10% Power)
Feedwater Conductivity (μS/cm)	<0.065	<0.15
Condensate Conductivity (CDI) (μS/cm)	<0.10	<10
Feedwater Total Copper (ppb)	<0.5	
Feedwater Total Iron (ppb)	<5.0	
CDE[b] or Feedwater Dissolved Oxygen (ppb)	>15 <200[c]	<200[a]
Condensate Dissolved Oxygen (ppb)	>15 <200[c]	
Feedwater Suspended Corrosion Products (ppb)		<100

[a] After establishing condenser vacuum
[b] Polished condensate
[c] Upper limit may be plant specific to ensure consistency with ECP requirements

Table 2-6 BWR Reactor Water

PARAMETER	POWER OPERATION > 10% POWER	STARTUP/HOT STANDBY (≥200F to <10% Power)
Local ECP[a] (mV, SHE)	(b)	
Conductivity (μS/cm)	<0.3	<1.0
Chloride (ppb)	<5	<100
Sulfate (ppb)	<5	<100
Zinc (ppb)	(c)	
Dissolved Oxygen (ppb)	(d)	<300

[a] Assumes Hydrogen Water Chemistry (HWC)
(b) Established by utility. < -230 mV (SHE) suggested
(c) Consistent with utility program for zinc injection
(d) Plant-specific value during hydrogen addition

Table 2-7 BWR Control Rod Drive Water

PARAMETER	LIMIT
Conductivity (μS/cm)	<0.15
Dissolved Oxygen (ppb)	<200

2.2.1 BWR Normal Water Chemistry/Hydrogen Water Chemistry

The purpose of this discussion is to evaluate the impact of BWR water chemistry, developed specifically for the reactor internals, on the non-class 1 components contained in the same fluid loop (e.g., main steam, condensdate, and feedwater systems). Since the 1960s, the susceptibility of BWR components to IGSCC and other types of corrosion have been known. Significant research and testing has provided an understanding of aging mechanisms, and has developed water chemistries and methods that mitigate IGSCC. The latest guidelines and technical bases are found in the EPRI BWR Water Chemistry Guidelines--1996 Revision (Reference 30). This document strengthens the recommendation for hydrogen waters chemistry (HWC), provides methodology for plant specific water chemistry program development, and discusses the side effects of HWC. Although the EPRI guidelines concentrate on the mitigation of SCC for reactor internal components and recirculation piping, consideration also is given to BOP components in the same loop (i.e., parts of the feedwater, condensate, and main steam systems). Flow-accelerated corrosion (FAC) or erosion-corrosion is an example of HWC side effects.

The decision to implement HWC requires a trade-off between the benefits, i.e., increased life of the reactor vessel internal components, and the costs, i.e., increased radiation exposure and direct outlays. A cost benefit analysis for HWC must explicitly address the uncertainties in many of the important factors, such as the likelihood of SCC and the increase in exposure. Therefore, the decision to implement HWC is plant-specific and the degree of hydrogen injection, if implemented, may be plant-specific. According to Reference 30, eight of the BWROG plants are using HWC and thirteen plan HWC installations between 1997 and 2000. For those plants using HWC, years of operation prior to implementation ranged from 5 to 13 years.

Depending on the specific water chemistry control objectives, Table 2-8 provides the relative amount of hydrogen needed to achieve IGSCC protection in most reactors [30].

Table 2-8: SCC Mitigation Alternatives

Identification	Mitigation Option	Hydrogen Added in Feedwater (ppm)
NWC	Normal Water Chemistry	0
HWC-L	Hydrogen Addition – Low	0.4 to <1.0
HWC-M	Hydrogen Addition – Moderate	1.0 to <2.0
HWC-H	Hydrogen Addition – High	≥2.0
HWC-NMCA(Noble Metal Chemical Addition)	NMCA with Low H_2 Addition	≥0.4

Generic rule based logic for the evaluation of aging effects for BWR power production loop components would be feasible if:

1. All BWRs were of the same design
2. All BWRs were of the same core power density
3. All BWRs had the same core management strategy
4. All BWRs had similar dose rate limitations for the power production loop
5. All BWRs had consistent operating water quality history or started operation with current improved water chemistry guidelines

However, this is not the case as shown by the years of research and data gathering that supports the plant-specific nature of aging of these components. Most of the work required to evaluate component remaining or potential life in the power production loop has already been accomplished through the recommended economic evaluations for HWC and the responses to the NRC Generic Letters, Information Notices, and Bulletins regarding erosion-corrosion and IGSCC. These evaluations of IGSCC and erosion-corrosion in BWR plants are more accurate than the generic rule-based logic of this mechanical tool and, in addition, address the plant-specific concerns. The stress corrosion cracking and erosion-corrosion effects are well known and should be adequately addressed in the Water Chemistry and Erosion-Corrosion programs for each plant. Therefore, this tool treats systems in the BWR power production loop (i.e., main steam, condensate, and feedwater) as special cases of the treated water environment regarding SCC in stainless steels and erosion-corrosion in carbon steels. Specifically, the evaluation logic will default conservatively for these aging effects.

3. AGING EFFECTS

The Treated Water Tool identifies potential aging effects that result from age-related degradation mechanisms. Where specific mechanisms are not applicable under the environmental and material conditions covered by this tool, justification is provided for a "not applicable" determination. For those effects that are potential, a detailed discussion of the environmental conditions necessary for the effects to be active is included. Many different degradation mechanisms are covered in this tool, however, the aging effects resulting from these mechanisms can be included in four categories: 1) loss of material, 2) cracking, 3) reduction of fracture toughness, and 4) distortion.

3.1 Loss of Material

Aging mechanisms that can lead to loss of the metallic materials listed in Section 2.1 are general corrosion, galvanic corrosion, crevice corrosion, pitting corrosion, erosion and erosion-corrosion, microbiologically-influenced corrosion, and wear. The cause of each aging mechanism is discussed in Sections 3.1.1 through 3.1.8.

3.1.1 General Corrosion

General corrosion is the result of a chemical or electrochemical reaction between a material and an aggressive environment. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup. General corrosion requires an aggressive environment and materials susceptible to that environment. Wrought austenitic stainless steel, CASS, nickel-base alloys and copper alloys are not susceptible to general corrosion in the treated water environments discussed in Section 2.2.

At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are required for iron corrosion. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any practical extent. However, carbon and low-alloy steels as well as cast iron are susceptible to general corrosion in systems using treated water. Although general corrosion is, in many cases, predictable and can be accounted for by a corrosion allowance, general corrosion is an applicable aging mechanism for such components. Aging management of components and material can include consideration of design corrosion allowances, however, it is inherent on each plant to assure that actual experienced material loss will not prevent these components from performing their intended functions through the license renewal period. As long as an allowance is used and it is adequate for the period of extended operation required for license renewal, general corrosion should not be a concern.

As discussed in Section 2, this tool considers the addition of lined or coated components. When credit is taken for coatings or linings, the user must ensure their integrity. The adequacy of programs to inspect/monitor linings or coatings should consider the inaccessibility of components such as buried or embedded piping.

3.1.2 Selective Leaching

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Copper-zinc alloys containing greater than 15% Zn are susceptible to selective leaching. Yellow brass (30% zinc and 70% copper) and Muntz metal (40% Zinc and 60% Copper) are susceptible to this mechanism. Copper alloys with a copper content in excess of 85% resist dezincification. The addition of small amounts of alloying elements such as tin, phosphorus, arsenic and antimony effectively inhibits dezincification [1, 7]. The addition of 1% tin to brass, for example, decreases the susceptibility to selective leaching [1].

There are two general types of dezincification, uniform attack and localized plug attack. Slightly acidic water, low in salt content and at room temperature, is likely to produce uniform attack, whereas neutral or alkaline water, high in salt content and above room temperature, often produces plug-type attack. In both types of dezincification the zinc ions stay in solution, while the copper plates back on the surface of the brass. The dissolved zinc can corrode slowly in pure waters by the cathodic ion reduction of water into hydrogen gas and hydroxide ions [7]. For this reason, dezincification can proceed in the absence of oxygen. The rate of corrosion, however, is increased in the presence of oxygen. This process occurs in clean water with no additional contaminant required for initiation [7].

Dezincification is the usual form of corrosion for susceptible copper alloys in prolonged contact with waters high in oxygen and carbon dioxide, and most often is associated with quiescent or slowly moving solutions.

Gray cast iron can also display the effects of selective leaching even in relatively mild environments. Selective leaching of the iron or steel matrix leaves a graphitic network. The graphite is cathodic to iron, providing a galvanic cell. The iron is dissolved, leaving a porous mass consisting of graphite, voids, and rust. If the cast iron is in an environment that corrodes this metal rapidly (e.g., saltwater), uniform corrosion can occur with a rapid loss of material strength which can go undetected since the corrosion appears superficial [7].

Aluminum bronzes containing greater than 8% aluminum are also susceptible to de-alloying of the aluminum in a similar manner to the dezincification of brass [7]. Aluminum brasses are resistant to impingement attack where turbulent high velocity saline water is the fluid. These alloys form a tough corrosion resistant protective coating due to the buildup of aluminum oxide. Proper quench and temper treatments for some of the aluminum bronzes produces a tempered structure that is superior in corrosion resistance to the normal annealed structures. This degradation effect has been noted specifically in acid solutions, however, it was also noted that massive effects occurred where the solution contained chloride ions [7]. Unless they are inhibited by adding 0.02 to 0.10%. As, aluminum brasses should be considered susceptible to selective leaching.

3.1.3 Galvanic Corrosion

Galvanic corrosion occurs when materials with different electrochemical potentials are in contact in the presence of a corrosive environment [7]. Components within treated water systems may exhibit galvanic corrosion if carbon steels, low alloy steels or cast iron materials are in contact with wrought austenitic stainless steel, CASS or nickel-base alloys. (Cast iron and carbon steel are grouped together in the galvanic series chart and will, therefore, demonstrate similar susceptibility to this aging effect.) This galvanic corrosion can occur if cladding or organic protective internal coatings on tanks are flawed such that dissimilar metals, that are electrically connected, are exposed to a corrosive environment. Galvanic corrosion may also be a concern at treated water system interfaces where connecting systems use carbon steel, low alloy steel or cast iron fittings and piping. However, dissolution of the ferritic materials would occur preferentially under these circumstances [7] since the more corrosion resistant material (i.e., stainless steel or nickel-base alloy) acts as the cathode. Therefore, wrought austenitic stainless steel, CASS and nickel-base alloys are not susceptible to loss of material because of galvanic corrosion.

When cast iron is used in treated water systems and is in contact with dissimilar metals, design features are usually included to control the rate of corrosion. Heat exchangers, for example, may have sacrificial anodes and/or coatings where there is contact between dissimilar materials. It is important in any aging management program to assure that these design features are maintained through the license renewal period (i.e. periodic sacrificial anode replacement and coating verification).

Copper alloys are in the middle of the galvanic series with steel, alloy steel and cast iron being more anodic (or active) and the stainless steels, nickel alloys and titanium being more cathodic (or passive). When coupled with the more anodic materials such as cast iron or carbon steel, the copper alloys exhibit reduced corrosion effects, whereas the cast iron or carbon steel will be corroded. Conversely, when galvanically coupled to the more cathodic materials such as stainless steel, titanium or graphite, the copper alloys may demonstrate an increased susceptibility to corrosion [1,7].

There are five methods of eliminating or significantly reducing galvanic corrosion: 1) Selecting dissimilar metals that are as close as possible to each other in the galvanic series. 2) Avoiding coupling of small anodes to large cathodes. 3) Insulating dissimilar metals wherever practicable. 4) Applying coatings and keeping them in good repair, particularly on the cathodic member. 5) Using a sacrificial anode - that is, coupling the system to a third metal that is anodic to both structural metals.

Carbon steels, low-alloy steels and cast irons that are in contact with stainless, CASS, or nickel-base alloys and are subjected to treated water may be susceptible to galvanic corrosion. Copper alloys are also susceptible when coupled to a more anodic stainless and when in contact with nickel alloys, titanium or graphite. However, the rate of dissolution of the ferritic material is expected to be low because of low impurities and low conductivity of treated water.

3.1.4 Crevice Corrosion

Crevice corrosion occurs in crevices or shielded areas that allow a corrosive environment to develop within the crevice. The nature of crevices, especially for those very small in size, is such that low flow or stagnant conditions can exist in the crevice regions even under system flowing conditions. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads where contaminants can concentrate [7]. In addition to stagnant conditions in the crevice, an oxygen content in the fluid above 100 ppb is required to initiate and perpetuate crevice corrosion [8]. Although the oxygen content in crevices can differ significantly from the bulk fluid oxygen levels due to oxygen depletion, etc., a bulk fluid oxygen level to sustain the chemical reaction is necessary for the continued corrosion in the crevice [7].

Although not required for crevice corrosion, any impurities and high temperatures significantly increase the rate at which crevice corrosion occurs. Crevice corrosion is not expected to cause excessive degradation in crevice joints such as socket welds or flange joints in a properly controlled low impurity environment [8]. Small amounts of crevice corrosion can degrade the performance of bearings and mechanical linkages that require small clearances, however, this degradation impacts only an active function, which is outside the scope of license renewal.

Crevice corrosion is a potential aging mechanism for carbon and low-alloy steels provided that the oxygen levels in the bulk fluid are greater than 100 ppb [8]. Cast iron and carbon steel undergo the same dissolution reaction [7], therefore, cast iron (in its plain form) is considered to have the same potential for crevice corrosion as carbon and low alloy steel.

Crevice corrosion of copper alloys is a result of oxygen depletion in the crevices such that the crevice metal is anodic relative to metal outside the crevice that is exposed to an oxygen-bearing environment [1]. Crevices are present throughout piping and equipment at connections, discontinuities in material, tube to tubesheet interfaces, etc. Corrosion susceptibility is increased in these areas because of foreign objects or debris such as dirt, pieces of shell, or vegetation in the crevice[1]. It can also result from the accumulation of rust, permeable scales or deposit of corrosion products at the crevice location. Another form of crevice corrosion can occur at a gas to fluid interface. This form of crevice corrosion is commonly called water-line attack because the corrosion occurs just below the water line [1]. Copper zinc alloys with greater than 15% Zn. exhibit high resistance to pitting/crevice corrosion whereas copper zinc alloys with less than 15% Zn. are susceptible [1]. Aluminum bronze alloys with greater than 8% aluminum are also highly susceptible to pitting. When the aluminum content is greater than 8% the aluminum is present in what is referred to as the "alpha-beta" phase, which is much less resistant to corrosion than the "alpha" phase aluminum present in bronzes containing less than 8% aluminum. The copper nickel alloys have also demonstrated susceptibility to pitting/crevice corrosion in aqueous environments [1,7].

3.1.5 Pitting Corrosion

Pitting corrosion is more common with passive materials such as wrought austenitic stainless steels and nickel-base alloy steels than with non-passive materials. All nuclear plant materials are susceptible to pitting corrosion under certain conditions. Alloys containing molybdenum (e.g., Type 316 or 316L, CF-3M, and CF-8M) are somewhat more resistant to pitting. Oxygen levels above 100 ppb in conjunction with impurities such as chloride, fluoride, sulfate or copper are required to initiate pitting in carbon steel, low-alloy steel, wrought austenitic stainless steel, CASS, nickel-base alloys, and cast iron[7,8,17,21]. Stagnant or low flow conditions which enables impurities to adhere to the metal surface is also required for pitting corrosion to occur. Areas where sludge piles and/or crevices exist are particularly susceptible to pitting corrosion.

Pitting is an aging mechanism for copper alloys as with most commercial metals. Pitting can occur either as localized or general attack. Localized attack takes the form of various shapes and sizes and is typically concentrated on surface locations at which the protective film has been broken, and where non-protective deposits of scale, dirt or other substances are present [1]. General pitting takes the form of a roughened and irregular appearance over the entire material surface. Pitting and crevice corrosion are similar corrosion mechanisms with crevice corrosion sometimes considered localized pitting in a crevice. Where crevice corrosion occurs in crevices that may contain stagnant fluid even under system flowing conditions, pitting requires either low flow or stagnant conditions to sustain the corrosion reaction and to provide for the concentration of contaminants [1]. While copper alloys are generally resistant to pitting and crevice corrosion, copper zinc alloys with less than 15% Zn are susceptible. Aluminum bronzes with greater than 8% Al, and copper nickel alloys are considered susceptible to pitting under stagnant or low flow conditions.

Maintaining an adequate flow rate will minimize pitting corrosion by preventing impurities from adhering to the material surface [8,17]. A low flow threshold for the treated water tool is defined to be < 3 ft/sec [14].

3.1.6 Erosion and Erosion-Corrosion

Erosion

Material loss because of erosion is possible only if the fluid contains particulates in the fluid stream that impinge upon the surface of the metal. Regions that are susceptible to erosion are flow discontinuities (e.g. elbows, tees, branch connections) where fluid velocities are high. Treated water chemistry and filtration requirements typically preclude the buildup of particulates that could contribute to abrasive erosion of carbon, low-alloy, wrought austenitic stainless steel, cast iron, CASS, copper alloys and nickel-base alloys. Lined or coated components are susceptible to damage of the lining/coating under harsh conditions, which results in corrosion potential for the base material in the eroded locations [4]. However, where particulates are not controlled, erosion is a plausible aging effect. Carbon steel, low-alloy, cast iron, wrought austenitic stainless steel, CASS, copper alloys and nickel-base alloys are all susceptible to erosion [1, 7, 33].

Erosion-Corrosion

Erosion-corrosion, also called flow-accelerated corrosion (FAC) is the loss of material caused by the combined actions of erosion by a flowing fluid and corrosion of the newly exposed base material by the flowing fluid. Protective oxide films provide resistance to erosion-corrosion; mechanical removal or dissolution of the film exposes the surface to further film production. Repetition of this process leads to thinning of the metal. The extent of erosion-corrosion is influenced by (1) fluid flow velocity, (2) environmental characteristics (temperature and fluid chemistry), and (3) material susceptibility. Wrought austenitic stainless steel, CASS, nickel-base alloys used in treated water environments are resistant to erosion-corrosion [4,19].

Flow rates less than 6 ft/sec will not cause erosion-corrosion of carbon and low-alloy steels [18]. Carbon steel and plain cast iron have demonstrated similar corrosion characteristics in moving sea water at different velocities [7] and have similar erosion-corrosion characteristics for the purpose of this tool. Temperature, pH, and oxygen influence erosion-corrosion in carbon and low-alloy steels. High pH levels (>9) can eliminate erosion-corrosion as a concern [7]. Erosion-corrosion rates are greatest at temperatures of 100 to 200C (212 to 392F) and decrease rapidly above and below this temperature range [5,22]. Carbon steels with very low levels of alloying elements exhibit higher rates of erosion-corrosion compared to low alloy steels. The same is true of cast iron with different alloying materials providing varying degrees of erosion-corrosion resistance. Piping layouts such as elbows, small radius of change of direction, and branch connections of 90-degrees are most susceptible to erosion-corrosion [5,22]. Instances of erosion-corrosion have been observed and are discussed further in Section 3.5.

The use of HWC in a BWR reduces the level of dissolved oxygen in the power generation loop, primarily for components located in the steam cycle. Figure 3-15 in Reference 30 shows the effect of dissolved oxygen on FAC. Steam side locations where the dissolved oxygen is between 7 and 50 ppb tend to be affected by HWC. In most BWR plants, such locations are found in the carbon steel RWCU piping, heater drain, moisture separator drain, and in some of the middle extraction steam lines.

As supported by NRC generic correspondence and historical data, erosion-corrosion is equally a concern in PWR secondary systems. Most all US plants have made predictions of FAC rates using CHECKWORKS or other FAC modeling codes.

The evaluation of erosion-corrosion is conservatively treated as a potential aging mechanism in the feedwater, steam, and condensate systems of both PWRs and BWRs. Erosion-corrosion is also considered a potential aging mechanism for the HPCI and the RCIC systems in BWRs. All plants have Erosion-Corrosion programs in place. The utilities can discuss the plant specific analyses and programs to mitigate the concern in the section on Demonstration of Aging Management. This discussion would include commitments to GL 89-08 and consideration of Information Notices 82-22, 86-106-suppl. 1, 2, and 3, 87-36, 88-17, 89-53, 91-18, rev 0, 1, 92-07, 92-35, 93-21, and 95-11 and Bulletin 87-01.

Because of the relatively lower hardness and strength of some copper alloys, many are somewhat susceptible to erosion corrosion. Copper alloys, however, are used extensively in nuclear plant heat exchanger applications because of overall corrosion resistance in harsh aqueous environments and numerous copper alloys are available that are highly resistant to erosion corrosion [1]. (Appendix G of these Mechanical Tools addresses heat exchanger degradation in much more detail and should be consulted for those components.) Even the highly resistant alloys are not immune to erosion corrosion and exhibit erosion corrosion rates at high velocities which are similar to those exhibited by carbon steel and cast iron under similar conditions [7]. The copper alloys should be considered susceptible to erosion corrosion where high velocities, constricted flow or change in fluid direction occurs.

A phenomenon that has been observed in austenitic stainless steel systems is cavitation erosion. Rapidly forming and collapsing gas bubbles may produce shock waves with pressures as high as 60,000 psi which leads to damage that is similar to pitting, except that the pits are closely spaced causing a roughened surface[7]. Cavitation erosion is typically associated with improper operation of pumps, valves, and stationary components such as an orifice or pressure reducing device. Examples include inadequate net positive suction head (NPSH) for pumps, high turndown for valves, or operation below vapor pressure for any component. Cavitation erosion is considered a design deficiency, which will be detected and corrected during the current term of operation. Loss of material because of cavitation erosion is not an applicable aging effect for the period of extended operation.

3.1.7 MIC

Microbiologically influenced corrosion (MIC) is corrosive attack accelerated by the influence of microbiological activity. MIC usually occurs at temperatures between 50 and 120F, however, microbes can withstand a wide range of temperatures (15 to 210^{o}F) [32]. These organisms have been observed in mediums with pH values between 0 and 10.5 and under pressures up to 15,000 psi [1]. Due to the number of different microorganisms involved in MIC and the wide array of environments that can support the growth of microbiological activity, material loss can be caused by a variety of different chemical reactions or material property changes. Typically, MIC is manifested as a localized loss of material similar to pitting type corrosion. The different types of microbes can grow with or without oxygen and can thrive in many chemical environments. Some anaerobic organisms reduce sulfate to sulfide ions which influences both anodic and cathodic reactions on iron surfaces [1, 18]. Several forms can metabolize NO_3, which is used widely as a corrosion inhibitor. These species produce many different byproducts, resulting in accelerated corrosion of certain alloys. Some aerobic organisms produce sulfuric acid by oxidizing sulfur or sulfur-bearing compounds. The ammonium producing variety increases the corrosion of copper and its alloys [1].

MIC is not likely in treated water systems where sulfates are low (<100 ppb). However, contamination of treated water systems can lead to MIC. One example of MIC in treated water components is torus damage at BWRs. Treated water systems typically are low in the nutrients required to sustain microorganisms, but in stagnant or low flowing areas, corrosion products and contaminants can accumulate and settle. The same contamination source for the microorganism could also allow introduction of the nutrients required to sustain these microbes. There are several sources of nutrients and microorganisms. Heat exchangers with treated water on one side and either raw water or lube oil on the other side have the potential for contamination if leakage exists for a considerable time period. In some cases the source of the treated water may have been contaminated, especially if the source is open to air or if there is inadequate control on makeup or other interfacing systems. Many emergency feedwater systems at PWRs are cross connected to the raw water system and contamination is possible during testing or inadvertent opening of valves. Maintenance of treated water system components can also result in contamination.

There are many treated water systems such as the borated emergency core cooling systems in PWRs that have not experienced MIC problems during the life of the plant. The potential for MIC contamination of these systems is highly unlikely and is not expected to be a concern during the license renewal period.

In summary, MIC is a potential aging effect for treated water, however, it is not likely unless the treated water has been contaminated with the microbes necessary to cause MIC damage.

3.1.8 Wear and Fretting

Wear results from relative motion between two surfaces, from the influences of hard, abrasive particles or fluid streams, and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting) [2]. Loss of material from erosion and erosion/corrosion is discussed in Section 3.1.6. Loss of material on external surfaces by wear and fretting is addressed in Appendix E. Wear and fretting on internal pressure boundary surfaces (e.g., on pump casings and valve bodies caused by cavitation) is under review by the NRC and industry. The user of this tool should review regulatory correspondence and industry technical reports, etc., after the issuance of this document to determine if pressure boundaries of pumps and valves should be evaluated for potential wear and fretting.

3.1.8.1 Wear

Wear can result from the movement of a material in relation to another material that occur during active functions that are not addressed by this tool (e.g., pump and valve operations). General wear is, therefore, not applicable for the equipment covered by these tools.

3.1.8.2 Fretting

Fretting is caused by small amplitude vibratory motion [e.g., flow induced vibration (FIV)] that results in removal of material between two contacting surfaces. With the exception of heat exchangers, and external surfaces of mechanical equipment, passive components in the raw water/carbon steel and stainless steel systems are not susceptible to this mechanism. Heat exchangers and external surfaces are evaluated separately in Appendices G and E respectively. This mechanism is, therefore, not considered applicable in this tool.

3.2 Cracking

Service induced cracking (initiation and growth) of base metal or weld metal may result from one or more of the following aging mechanisms: hydrogen blistering, stress-corrosion cracking, and fatigue. Growth of pre-existing flaws (i.e., material and fabrication flaws whose sizes and character were less than applicable fabrication acceptance standards) because of service operating stresses is not discussed in this appendix but is discussed in the Implementation Guide.

3.2.1 Hydrogen Damage

Hydrogen damage results from the absorption of hydrogen into the metal. It includes the degradation mechanisms of hydrogen blistering and embrittlement in ferrous metals [7,10]. Hydrogen damage usually manifests itself as hydrogen embrittlement in high strength steels and hydrogen blistering in low strength steels and irons. Hydrogen blistering occurs primarily in low strength carbon and low alloy steels in the temperature range of 30 to 300F [15]. Corrosion and the application of cathodic protection, electroplating, and other processes are major sources of hydrogen in metals. Hydrogen blistering is most prevalent in the petroleum industry, in storage tanks and in refining process [7]. A review of the failure data for BWR and PWR treated water systems show no evidence of hydrogen blistering; therefore, it is considered not applicable for carbon steels in treated water systems.

Another term for hydrogen embrittlement is sulfide stress cracking if the cracking is because of the presence of hydrogen sulfide. A few ppm of absorbed hydrogen can cause cracking [7]. At yield strengths of less than 120 ksi for carbon steels, low alloy steels and

cast iron, concern regarding hydrogen cracking is alleviated except when the material is temper embrittled [10]. Since the yield strength of most of the piping and components in treated water applications is on the order of 30 to 45 ksi, hydrogen embrittlement is considered not applicable for carbon steels. The yield strength of even the hardest ductile and malleable cast iron alloys is less than 100 ksi, with the plain cast irons in the same range as that noted above for the carbon and low alloy steel applications.
In most cases, austenitic stainless steels and copper alloys are immune to hydrogen damage although nickel-base alloy may be somewhat susceptible [7,10,16,20]. Therefore, hydrogen damage is considered not applicable to stainless steels and copper alloys.

3.2.2 Stress Corrosion Cracking

Stress corrosion cracking (SCC) occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. For a particular material, high stresses require less corrosive environments and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC can be categorized as either intergranular stress corrosion cracking (IGSCC) or transgranular stress corrosion cracking (TGSCC), depending upon the primary crack morphology. In addition, austenitic stainless steels exposed to a neutron fluence (>1 MeV) in excess of $1x10^{21}$ n/cm^2 [24] may be susceptible to irradiation-assisted stress-corrosion cracking (IASCC). However, non-Class 1 mechanical components will not receive fluence levels above $1x10^{21}$ n/cm^2 in the period of extended operation and are not susceptible to IASCC.

IGSCC is characterized by cracks propagating along the grain boundaries of the material. It is typically associated with materials containing excessive grain boundary precipitation or impurity segregation. Although IGSCC usually occurs in fluid mediums with high dissolved oxygen (>100 ppb), it can occur in a low oxygen environment. Preferential grain boundary precipitation of carbides in austenitic stainless steels and nickel-base alloys leads to a localized depletion of chromium in the vicinity of the grain boundary. This process is known as sensitization and renders the material susceptible to IGSCC.

Grain boundary segregation of impurities such as phosphorous, sulfur, and silicon is another mechanism that promotes IGSCC. Segregation can produce a grain boundary chemical composition with a significantly different electrochemical potential from that of the bulk alloy composition. The effect of this electrochemical potential difference is an increase in corrosion susceptibility at the grain boundaries.

TGSCC is characterized by cracks that propagate through (or across) the grains of the material. Numerous metallurgical factors, such as crystal structure, grain size and shape, dislocation density and geometry, and phase composition, affect TGSCC. It is most prevalent in austenitic stainless steels subjected to chlorides and oxygenated environments.

Intergranular attack (IGA), also known as intergranular corrosion, is similar in some respects to SCC; however, it is distinguished from SCC in that stress is not necessary for it to proceed. IGA is characterized by deterioration of grain boundaries without appreciable attack of adjacent grains. That is, the rate of attack on grain boundaries greatly exceeds that of the matrix material. Generally, materials and conditions that are susceptible to intergranular stress corrosion cracking will also be susceptible to IGA.

Stresses in materials are generally categorized as either applied or residual stresses. Applied stresses are the result of operating history and loading, or stresses applied during fabrication as a result of bolting, riveting, welding, bending, etc. Residual stresses are those stresses resulting from the actual fabrication of the material and include cold working, tube drawing, spinning, tooling, etc. [13]. These stresses are very difficult to ascertain for any given component or material and this detailed evaluation and identification of applied and residual stresses is beyond the scope of this tool. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and the environment. Increasing the stress tends to decrease the time for cracking to occur and, together with the specific temperature and environment to which a material is exposed, makes it extremely difficult to identify a minimum threshold stress level for SCC. Therefore, it is assumed that austenitic stainless steel, nickel-base alloy, and copper alloy evaluated using these tools contain stresses sufficient to initiate SCC if subjected to a corrosive environment. A discussion of the susceptibility of austenitic stainless steels, nickel-base alloys and copper alloys to SCC or IGA in a treated water environment is provided below.

SCC of Wrought Austenitic Stainless Steel and CASS

In treated water systems, dissolved oxygen, sulfates, fluorides, and chlorides can provide the necessary environment for SCC or IGA to occur. Stress corrosion cracking has been observed in high-purity water (i.e., low sulfates and halogens--less than 100 ppb-150 ppb) at temperatures greater than 200^{o}F and dissolved oxygen levels greater than 100 ppb [10]. The presence of impurities such as sulfates > 100 ppb, chlorides >150 ppb, or fluorides > 150 ppb are all by themselves sufficient to initiate SCC in austenitic stainless steels [9,10]. There have been reports of SCC of sensitized austenitic stainless steels in borated systems, with thiosulfate being identified as the critical species causing SCC. Laboratory tests showed that SCC could occur with very low concentrations (e.g., 100 ppb) of $Na_2S_2O_3$. Higher concentrations (e.g., 1000 ppb) of $Na_2S_2O_3$ were required in the presence of boric acid [9]. The EPRI Primary Water Chemistry Guideline: Revision 3 [29] uses a threshold level for sulfates of 150 ppb to require corrective action.

The susceptibility of austenitic stainless steels to SCC is enhanced if the materials are sensitized. Sensitization can occur after welding during cooling of the HAZ. High carbon content (>0.03%) wrought austenitic stainless steels can be sensitized which leaves the welded joint susceptible to IGSCC when the joint is exposed to high oxygenated water or contaminants such as halogens or sulfates. Instances of IGSCC of

Type 304 austenitic stainless steels in oxygenated borated water have been reported at several plants and are discussed in Sections 3.5 and 4.0.

For a discussion of SCC in stainless steel components influenced by BWR water chemistry, see Section 2.2.1.

SCC of Nickel-Base Alloys

In general, nickel-base alloys are more resistant to SCC in the presence of impurities and oxygenated water than is austenitic stainless steel. However, it is conservatively assumed that the threshold values of impurities reported above for austenitic stainless steels apply to nickel-base alloys (i.e. sulfates >100 ppb; chlorides > 150 ppb; and fluorides >150 ppb). In addition, nickel-base alloys are susceptible to SCC when exposed to high-purity deaerated water at elevated temperatures. Recent studies of Alloy 600 in a PWR environment [11] show that primary water stress-corrosion cracking (PWSCC) occurs when high tensile stress, high temperature, and a susceptible microstructure are simultaneously present. All failures of Alloy 600 components reported in the field resulted from high residual tensile stresses introduced during fabrication. Other factors that may possibly influence susceptibility include high lithium and high hydrogen content. Alloy 82 and Alloy 182 weld metals may also be susceptible to PWSCC.

Temperature is an important parameter in determining the susceptibility of nickel-base alloys to PWSCC. In addition, the non-Class 1 nickel-base alloy applications are subjected to low operating temperatures. PWSCC susceptibility of Alloy 600 is low when the temperature is less than 600°F[11]. A PWSCC screening threshold temperature of 500°F was arbitrarily chosen to conservatively apply to this Mechanical Tool. Therefore, PWSCC in nickel-base alloys is assumed to be insignificant when exposed to temperatures less than or equal to 500°F and to reactor coolant chemistry conditions described in the EPRI Water Chemistry Guide for the RCS [3].

SCC of Copper Based Alloys

Some copper alloys are very susceptible to stress corrosion cracking in the treated water environments encountered in nuclear plants. The necessary ingredients for SCC in copper alloys, as for all metals, are high stress in conjunction with an aggressive environment. The necessary chemical substance to cause SCC in copper alloys is ammonia or other ammonium compounds. These chemical substances are sometimes used in treated water systems to control the fluid pH or can be present as a result of an ammonium based cleaning solvent. Ammonia can also be present in the atmosphere as a result of organic decay. In addition to ammonia or ammonium compounds, oxygen and moisture are also required to promote SCC in the copper alloys while other contaminants such as carbon dioxide may act as catalysts to increase the rate of cracking. A thin moisture film on the metal surface is capable of absorbing a significant amount of ammonia, even from air containing a low ammonia concentration [1].

Copper alloys containing greater than 15% Zn are highly susceptible to stress-corrosion cracking. The best-known example of stress corrosion cracking is probably the “season cracking" of yellow brass ammunition shells in a moist ammonia filled environment [7,16]. Brass alloys containing less than 15% Zn exhibit almost no susceptibility to SCC. Conversely, brasses containing 20 to 40% Zn demonstrate high susceptibility to SCC, with susceptibility increasing as the Zn content is increased. Inhibited copper alloys produce by the addition of small amounts of other alloying elements (e.g. Sn, As, etc,) to brass alloys have demonstrated increased resistance to selective leaching, however, these "inhibited" alloys do not appear to provide an increased resistance to SCC [1]. All copper alloys, (both brasses and bronzes) containing in excess of 15% Zn should be considered susceptible to SCC regardless of any added inhibiting elements such as Sn or As.

Bronze (copper-tin alloys), copper nickel and copper silicon alloys are considerably more resistant to stress corrosion cracking than the copper-zinc (brasses) alloys [7, 16]. These alloys are not considered susceptible to SCC/IGA for this treated water tool. Aluminum bronze, however, has exhibited high susceptibility to SCC in a moist ammonia environment [1].

Intergranular corrosion of copper alloys does not occur frequently and, when it does occur, is usually associated with high-pressure steam environments. The effects of this degradation mechanism are similar to SCC except that mechanical stress is not required to initiate the intergranular corrosion [1]. Typically the alloys that are susceptible to SCC are also susceptible to intergranular corrosion. These include muntz metal, admiralty metal, yellow brass, commercial bronze and aluminum brasses. One exception to the inclusion rule appears to be silicon bronze alloys which are resistant to SCC but do demonstrate a susceptibility to intergranular corrosion. (Silicon bronze alloys are also susceptible to embrittlement in high pressure steam environments, which may be partially responsible for the susceptibility to intergranular corrosion of these alloys [1]).

SCC of Carbon and Low-Alloy Steels

SCC of carbon steels, low alloy steels and cast iron is possible particularly in aqueous chlorides. One of the most reliable methods of preventing SCC is to select a material with a yield strength of less than 100 ksi [9]. The yield strength of carbon and low alloy steels typically used in treated water systems is in the range from 30 to 45 ksi. Industry data does not exhibit widespread incidence of SCC in low strength carbon steels; however, there was one reported case suspected to be nitrate-induced SCC of carbon steel in a treated water system. For the purposes of this tool, SCC of carbon and low-alloy steels is not considered an applicable aging mechanism in treated water systems. SCC in higher strength bolting materials is discussed in the Bolted Closure Tool in Appendix F.

3.2.3 Fatigue

Fatigue cracking of carbon, low-alloy, wrought austenitic stainless steel, CASS, copper alloys and nickel-base alloys is discussed in Appendix H.

3.3 Reduction of Fracture Toughness

The fracture toughness of wrought austenitic stainless steel, CASS, and nickel-base alloys are typically higher than carbon steels, low-alloy steels and cast iron. Aging mechanisms that may lead to reduction of fracture toughness are thermal embrittlement, radiation embrittlement, and hydrogen embrittlement. The susceptibility of the materials listed in Section 2.1 to reduction of fracture toughness is discussed below.

3.3.1 Thermal Aging

Thermal embrittlement degrades the mechanical properties of material (strength, ductility, toughness) as a result of prolonged exposure to high temperatures. Carbon, low-alloy, cast iron, wrought austenitic stainless steel, copper alloys and nickel-base alloys are not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments [4,25,26,27,28]. However, CASS materials are susceptible to thermal embrittlement. The degree of susceptibility is dependent upon material composition and time at temperature. Castings with high ferrite and high molybdenum contents are more susceptible to thermal embrittlement than those with lower values. Recent fracture toughness comparisons between thermally aged CASS and SAW austenitic stainless steel weldments show that the lower bound toughness values of castings are comparable to stainless steel weldments currently in service [12].

CASS materials subjected to sustained temperatures below 250°C (482 °F) will not result in a reduction of room temperature Charpy impact energy below 50 ft-lb for exposure times of approximately 300,000 hours (for CASS with ferrite content of 40%) and approximately 2,500,000 hours for CASS with ferrite content of 14%) [Figure 1; Reference 12]. For a maximum exposure time of approximately 420,000 hours (48 EFPY), a screening temperature of 482°F is conservatively chosen because (1) the majority of nuclear grade materials are expected to contain a ferrite content well below 40%, and (2) the 50 ft-lb limit is very conservative when applied to cast austenitic materials--it is typically applied to ferritic materials (e.g., 10 CFR 50 Appendix G).

Cast materials that are below the temperature screening threshold of 482°F are not subject to significant reduction of fracture toughness for the period of extended operation. A description of acceptable aging management of reduction of fracture toughness for CASS materials may be found in the RCS Piping Report and EPRI report TR-106092 [4,12].

3.3.2 Radiation Embrittlement

Radiation embrittlement can result in a decrease in fracture toughness of metals and is not applicable to carbon and low-alloy steels, cast iron, wrought austenitic stainless steel, CASS, copper alloys and nickel-base alloys covered by this tool. The non-Class 1 components addressed with this tool are not within the reactor vessel beltline region and are not subjected to the neutron fluence required to embrittle these materials [4].

3.3.3 Hydrogen Embrittlement

See discussion in Section 3.2.1.

3.4 Distortion

Distortion may be caused by plastic deformation owing to temperature-related phenomena. In general, distortion is addressed by the design codes and is not considered an applicable aging effect. Creep is not a plausible aging mechanism since the high temperatures required for this mechanism to occur (generally at temperatures > 40% of the alloy melting point) are not observed in nuclear plant systems [10].

3.5 Operating History

A review of operational history was performed using NPRDS and review of NRC generic communications that apply to treated water PWR and BWR systems. Each is reported below.

3.5.1 NPRDS Review

Reported failures of safety and non-safety-related components in treated water systems at B&W, Combustion Engineering, and Westinghouse (W) PWRs and at General Electric (GE) BWRs were reviewed. Selected systems for PWRs included Letdown/Purification and Makeup (B&W), Decay Heat Removal/Low Pressure Injection (B&W), High Pressure Injection (B&W), High Pressure Safety Injection (CE), High Pressure Safety Injection (W), High Pressure Safety Injection Upper Head Injection (W), Main Steam (B&W, W, CE), Component Cooling Water (B&W, W, CE), Feedwater (B&W), Main Feedwater (W, CE), Emergency Feedwater (B&W), and Auxiliary Feedwater (W, CE). Selected systems for BWRs included Main Steam, Feedwater, Condensate, Reactor Core Isolation Cooling, RHR/Low Pressure Injection, High Pressure Coolant Injection, Low Pressure Core Spray, High Pressure Core Spray, Standby Liquid Control, Containment Spray, Reactor Building Closed Cooling Water, Isolation Condenser, and Nuclear Steam Supply Shutoff. The components selected for failure evaluation were accumulator, filter, pipe, pump, valve, and vessel. The failure modes investigated include age and normal usage, unknown and other. Excluded failure modes include plugged pipe, and active functions of valves and pumps.

Specifically, NPRDS failure mode search key words were:

- foreign material/substance
- particulate contamination
- normal wear

- welding process,
- abnormal stress
- abnormal wear
- mechanical damage
- aging/cyclic fatigue
- dirty
- corrosion
- mechanical binding/sticking
- mechanical interference
- environmental condition and other.

There were 5493 and 3369 records meeting the search condition(s)for the PWRs and BWRs, respectively. These records were reviewed and those considered not applicable to the license renewal scope were excluded (e.g., leakage past valve seat, pump/valve internals, valve will not open/close, setpoint drift, spring, bearing, mechanical damage, switch, misalignment, etc.). The remaining entries were categorized as shown in Tables 3-1 and 3-2 below. The failures in the first three categories involved consumables (e.g., packing, gaskets, and seals). The number of records and the percentage of total for the following categories were tabulated.

The data and observations for PWRs and BWRs are reported separately to identify any differences should they exist.

3.5.1.1 PWR NPRDS Data

Table 3-1 NPRDS Search Summary for PWR Systems

FAILURE CAUSES	NO. OF ENTRIES	% OF TOTAL*
Packing	2002	44.7%
Gaskets	1655	36.9%
Seals	501	11.2%
Threaded Connections	111	2.5%
Bolting	51	1.1%
Cracked Welds	84	1.9%
Corrosion	27	0.6%
Erosion-Corrosion	45	1.0%
Stress-Corrosion Cracking	2	0.04%
Water Hammer	2	0.04%
Dry Out	1	0.02%
Freezing	1	0.02%

* Percentage may be greater than 100 owing to multiple causes of failures.

Observations

1. The number of incidents of SCC reported in borated water systems as documented in CR 76-06 and Bulletin 79-17 were missing from failure data entries. This could be because of inconsistent and poor reporting practices prior to INPO taking responsibility for NPRDS in 1981. Although not reported, the corrective actions that resulted from plant-specific commitments to IE Bulletin 79-17, as described in Section 3.5.2, were effective in eliminating the incidents of IGSCC.

2. One of the two reported cases of SCC occurred in a borated water system and was attributed to contamination from halogens (chlorides and fluorides) in a stagnant 8-inch line. The other case of SCC occurred in a Component Cooling Water system piping weld.

3. Except for corrosion as a result of flange leaks, it appears that general corrosion is not occurring in borated water/stainless steel systems.

4. Over 93% of the reported failures were attributed to leaks in seals, packing, and gaskets.

5. Of the nine weld cracks reported for borated water systems, seven were in small connecting lines of 1 1/2-inch NPS or less and were attributed to vibration. One weld crack was in a charging pump casing and was attributed to high-cycle vibration. One was attributed to SCC as noted above.

6. Weld cracking reported for the MFW system was roughly twice that reported for the EFW and CCW systems. The least amount of weld cracking was reported for the MS system. Minor leakage as the result of weld cracking was usually in small connecting lines such as vent, drain, lube oil, relief valve connections, and vent nipples. The causes were attributed to vibration, hydrodynamic loading, thermal shock, thermal stratification, mechanical and cyclic stress.

7. Although threaded connection leaks were common, most were corrected by reapplying pipe thread tape or sealant and retightening.

8. As expected, most all erosion/corrosion failures were reported for the feedwater or main steam systems. The few reported cases of erosion/corrosion outside of the feedwater or main steam systems (e.g., EFW) were probably caused by cavitation problems or steam cutting in the turbine driven EFW pump steam supply lines.

9. Only about 3 1/2 to 4% of the reported failures were caused by age related mechanisms and many of these are considered questionable as to being truly age related as opposed to short-term or improper maintenance type failures.

3.5.1.2 BWR NPRDS Data

Table 3-2 NPRDS Search Summary for BWR Systems

FAILURE CAUSES	NO. OF ENTRIES	% OF TOTAL
Packing	1301	55.9%
Gaskets, O-Rings	378	16.2%
Seals	447	19.2%
Threaded Connections	17	0.7%
Loose/Broken Bolts/Nuts/Screws	43	1.8%
Nipples, Fittings	54	2.3%
Weld Defect/Crack/Failure	28	1.2%
Erosion	14	0.6%
Erosion-Corrosion	4	0.17%
Corrosion	9	0.38%
Stress Corrosion Cracking	7	0.30%
Pinhole Leak	5	0.21%
Pump/Valve Body Leak	13	0.56%
Flex Line	4	0.17%
Pipe Fatigue Crack	1	0.04%
Cavitation	1	0.04%
Waterhammer	1	0.04%

3.6 Observations

1. Over 91% of the reported failures were attributed to leaks in seals, packing, gaskets, and O-rings.

2. Weld defects/cracks/failures were predominately in the main steam, feedwater, and RHR/low pressure injection systems. The leakage as a result of weld cracking was most always minor and usually in small connecting lines such as vent, drain, lube oil, and relief valve connections. Most of the causes were attributed to vibration, hydrodynamic loading, and thermal or cyclic stresses.

3. Two notable exceptions to the observations regarding weld failures occurred at the LaSalle 1&2 plants in the high pressure core spray systems. The material was 304SS in 14-inch piping and the fluid was reactor/primary water. The failure at LaSalle 1 resulted in a 30 gpm leak. Samples showed the cause to be biological corrosion of the weld areas, which are the only referral to biological corrosion or MIC in the treated water entries. Isolated contamination could be the cause of these failures.

4. Loose/Broken Bolts/Nuts/Screws were common across all the systems reported. Leakage was mostly minor and causes were attributed to vibration, improper torquing, and thermal/cyclic stresses.

5. There were seven entries for intergranular stress corrosion cracking. Two of these entries were in the pump wear ring of the LPI pumps which ordinarily would not be included since the failures occurred in active components that are not considered in aging evaluation. They were included since SCC is infrequent in the treated water systems. Four of the entries were in the Isolation Condenser systems. One of the four entries was at Oyster Creek involving primary water and the heat affected zone (HAZ) of 8-inch, 304SS piping. Three of the four entries were reported at Nine Mile Point involving primary water and 316SS valves and piping. The associated piping was replaced in these four Isolation Condenser system cases. The only other entry was in a Low Pressure Core Spray system involving 304SS piping.

6. Usually the entries in the Pinhole Leak or Pump/Valve Body Leak categories did not specify enough information to determine the aging mechanisms involved. Cavitation and corrosion were identified in a few cases.

7. As in the PWR data, most of the erosion or erosion-corrosion failures were reported in the Feedwater or Main Steam systems. Similarly, corrosion is not widespread in the treated water systems and mostly limited to the Feedwater and Condensate systems.

8. Only about 4-5% of the reported failures were caused by age related mechanisms and many of these are considered questionable as to being truly age related as opposed to short-term or improper maintenance type failures.

3.6.1 NRC Generic Communications

NRC generic communications dating back to 1973 were reviewed for their applicability to aging degradation of non-Class 1 systems containing treated water components. The documents searched were: Circulars, Bulletins, Information Notices, and Generic Letters. Of these, 43 were considered to be related, either directly or indirectly, to treated water components. These included 1 Circular, 31 Information Notices, 4 Generic Letters, and 7 IE Bulletins. These entries are discussed briefly below.

Circulars

CR 76-06: Stress-Corrosion Cracks in Stagnant, Low Pressure Stainless Piping Containing Boric Acid Solution at PWRs

See discussions of IN 79-19 and IE Bulletin 79-17.

Information Notices

IN 79-19: Pipe Cracks in Stagnant Borated Water Systems at PWR Plants

Instances of cracking of stainless steel piping in a stagnant borated water environment were reported in CR 76-06 and IE BL 79-17. The cracking occurred preferentially in the HAZ of welded joints where a sensitized microstructure was found. Of particular susceptibility were stainless steel welded joints with high carbon (>0.03%) content that were exposed to stagnant oxygenated boric acid in the presence of contaminants such as halogens and sulfates.

IN 80-05: Chloride Contamination of Safety Related Piping and Components

IN 80-05 alerted licensees to an instance of corrosion of stainless steel as a result of contact with a fire retardant protective coating containing cementious oxychloride materials. These materials, when accidentally sprayed on stainless steel, have led to significant corrosion.

IN 80-38: Cracking In Charging Pump Casing Cladding

In January 1980 Commonwealth Edison Company (CECo) reported to the NRC that a radiographic examination had revealed crack indications in the cladding on the suction end plate of the 1A charging pump at Zion Unit 1. This pump injections borated water to the reactor loops. ASME Section XI inservice inspection rules referenced in the plant technical specification requires pump examination only once during the 10 year service interval and this pump had been in service about 7 years. . The pump casing end assembly in the area of interest consists of a suction end plate of A515 grade 60 carbon steel plate welded to the casing barrel forging of A266 class 1 carbon steel using an Inconel weldment. The entire inner surface is clad with type 308 stainless steel applied by submerged arc welding. It was determined that initiation and propagation of the clad cracks probably resulted from stress concentration and dilution effects in the initial corner bead pass due to the difficult access and bead sequencing required by the fairly sharp corner geometry. Extension of the cracks at the base metalclad interface ranged to a depth of 1/16 inch maximum in the 1-1/2 inch thick base material. These crack tip areas were well blunted and slightly cavitated from corrosion effects due lengthy exposure to the localized boric acid attack. Examination of the crack morphology revealed that the clad cracking essentially arrested at the base metal-clad interface and that base metal corrosion progressed at a relatively slow rate. Based on the available information no immediate safety concern is indicated. However, the observed conditions reveal a potential source of pump degradation over long term operations. Therefore, to assure maximum availability, it appears prudent to perform a nondestructive examination of this pump type at the earliest practical time during the first code required in-service inspection interval and if cracking is confirmed, take appropriate corrective actions per the rules of ASME Section XI BP&V Code.

IN 80-15: Axial (Longitudinal) Oriented Cracking in Piping

IN 80-15 reported an instance of cracking during a pressure test of stainless steel piping at a BWR in the core spray piping. The cracking occurred adjacent to a shop weld joining a 90° elbow and a wedge section of elbow material used to extend the elbow to 105°.

Augmented inspections prior to the pressure test failed to identify the cracking. The cracking occurred in service sensitive (i.e., sensitized sections) of the Type 304 stainless steel piping.

IN 81-04: Cracking in Main Steam Lines
Crack indication was observed in the I.D. counterbore area of a weldment on the in-line "T" fitting that connects the vertical run of 30 inch piping to the safety relief valve header and 30 inch main steam line of the steam generator.

Cracking was also observed in the weld counterbore at the opposite end of the T-fitting during visual examination of the piping interior. Radiographic examination of other SGs at the same site indicated similar crack indications at the same locations. No cause was identified at the time of the IN.

IN 82-22: Failures in Turbine Exhaust Lines
Steam erosion caused pipe rupture at steam extraction line. Utilities performed pipe wall thickness measurements to predict when it reaches a minimum acceptable thickness before it is replaced. INPO has developed a guideline and recommendation to perform predictive calculations.

IN 84-18: Stress-Corrosion Cracking in PWR System
The introduction of corrodants to the RCS through contaminants in purchased boric acid and at the free surface of the spent fuel pool is discussed in IN 84-18. Water chemistry requirements include a check for sulfates, organics, and other contaminants that can cause SCC during all modes of operation, including shutdown and refueling.

IN 84-32: Auxiliary Feedwater Sparger and Pipe Hanger Damage
The damage was attributed to water hammer caused by the design of the auxiliary feedwater piping into the steam generators.

IN 84-41: IGSCC in BWR Plants
Two 4-inch diameter jet pump instrument line nozzle welds at Browns Ferry Unit 3 had two pinhole leaks in the safe-end to reducer weld. UT revealed extensive axial cracks on both welds.

IN 84-87: Piping Thermal Deflection Induced by Stratified Flow
Thermal deflection induced by stratified flow has caused feedwater pipe support failures and feedwater leaks because of deformed piping sections (pipe bending). This was originally thought to be caused by water hammer but complex design features at some BWRs allow slow mixing of hot reactor coolant water and cold feedwater which will result in thermal stratification and pipe bending.

IN 85-024: Failures of Protective Coatings in Pipes and Heat Exchangers
Information Notice 85-024 alerted licensees to a potentially significant problem pertaining to the selection and application of protective coatings for safety related use.

Two instances of blistering and delamination of Plasite coatings were reported. The first involved a Plasite lined 24-inch diameter pipe that experienced delamination and peeling in the pipe elbow sections; the straight sections were not affected. Failures in the elbow sections were attributed to improper installation of the coating because of inadequate curing.

The second instance involved severe delamination and peeling of Plasite coatings in various diesel generator heat exchangers at one plant. The failures included severe blistering, moisture entrapment between layers of coating, delamination, peeling, and widespread rusting. Root cause evaluations showed the presence of cutting oils on the metallic surfaces prior to application of the coating, metallic surface that were too smooth prior to resin application, and insufficient time of curing.

IN 85-034: Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping
IN 85-34 alerted licensees to instances of cracking of stainless steel lines caused by the use of heat tracing. One plant experienced through-wall cracks in horizontal 1 inch NPS Type 304 stainless steel piping as a result of stress-corrosion cracking. Cracking was attributed to the concentration of chloride ions. The line is normally dry and heat tracing was used to dry the line following a hydrostatic test. As the water evaporated, chloride ions in the water used for hydrostatic testing concentrated in the section of horizontal run where the pipe sagged. Combinations of pipe sagging, concentrated chlorides, and application of heat induced stress-corrosion cracking.

IN 85-056: Inadequate Environment Control for Components and Systems in Extended Storage or Lay-up
IN 85-056 alerted licensees to problems that could occur to mechanical equipment if improperly laid up during construction or during plant outages. Instances of corrosion damage in emergency diesel heat exchangers and pinhole leaks in stainless steel service water systems were reported. This IN indicated that the cited examples represented a small sample of instances that occurred because of improper storage or lay-up. Appendix B 10 CFR 50.34(b)(6)(ii) requires a description of how the requirements of Appendix B will be satisfied during plant operation. Among the requirements of Appendix B, Criterion XIII addresses storage, cleaning, and preservation of materials and equipment.

IN 86-106, REV 0, 1, 2, 3: Feedwater Line Break
IN 86-106 alerted licensees to a feedwater pipe rupture because of pipe wall thinning. The pipe material was ASTM A-106B carbon steel and the elbow was 18-inch, extra strong ASTM A-234 Grade WPB carbon steel. This wall thinning was caused by erosion/corrosion; some corrosion pitting was also observed.

IN 87-36: Significant Unexpected Erosion of Feedwater Lines
Wall thinning has been experienced within straight sections of main feedwater system piping. EPRI code CHEC would not have required that the pipe wall in these straight

sections be examined. Erosion/corrosion of carbon steel is the cause of pipe wall thinning.

IN 88-17: Summary of Responses to NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
This Information Notice provides a summary of single and two-phase systems pipe wall thinning induced by erosion/corrosion to date. In IE Bulletin 87-01 the NRC requested all licensees to provide information concerning programs to monitor pipe wall thinning which are summarized in this IN. Internal piping erosion caused leaks in a feedpump minimum-flow line at LaSalle County Unit 1.

IN 88-37: Flow Blockage of Cooling Water to Safety System Components
This information alerted licensees to a potentially generic problem involving flow blockage in safety-related piping interconnections due to biofouling. This condition may occur and not be detected due to stagnant water in system interconnecting piping which is not routinely flushed or flow tested. The IN stressed the importance of maintaining these lines free of clams, corrosion, and other foreign material.

IN 88-87: Pump Wear and Foreign Objects in Plant Piping Systems
AFW pump casing excessive wear has produced foreign objects floating in the system causing flow blockage. Increased inspection was recommended.

IN 89-01: Valve Body Erosion
Significant but localized valve body internal surface wear because of erosion of carbon steel valve bodies has been detected. Although, this wear problem with carbon steel globe valve bodies was identified at one site in the 24-inch RHR/LPCI system and 16-inch suppression pool isolation valves, this information notice covers all carbon steel valve bodies in safety related systems. It is known that excessive throttling of globe valves (below their design flow range) can promote cavitation, which enhances internal valve body erosion.

IN 89-53: Rupture of Extraction Steam Line on High Pressure Turbine
Carbon steel pipe wall thinning on extraction steam line from a high pressure turbine caused pipe rupture. Abrasive erosion phenomenon is suspect owing to the turbulent flow pattern (inside diameter mismatch between the pipe and nozzle elbow) set up because of the geometry of an elbow section and the straight section of the attached pipe.

IN 89-80: Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping
This IN is for BWRs but it also emphasizes the importance of the thermal fatigue failures around welded joints owing to thermal stratification.

IN 91-05: Intergranular Stress-Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles
IN 91-05 alerted licensees to instances of IGSCC of PWR safety injection accumulator nozzles. Failures were reported at two PWRS. At one plant, the leak occurred in a nozzle submerged in borated water at the bottom of the accumulator. The cause of the failure was attributed to an improper fit-up at the nozzle-socket to pipe joint, which resulted in high stresses on the sensitized stainless steel nozzle. A failed nozzle at a second plant was discovered during the 10-year inservice inspection hydrostatic test. The leak was located in a 2-inch instrument nozzle. Subsequent root cause evaluation determined the failure to be IGSCC of the sensitized stainless steel nozzle. In both instances the failures were attributed to IGSCC of sensitized stainless steel nozzles.

IN 91-18, REV 0, 1: High-Energy Piping Failures Caused by Wall Thinning
IN 91-18 alerted licensees of continued signs of erosion/corrosion induced pipe wall thinning in high energy piping systems despite implementation of long-term monitoring programs pursuant to GL 89-08.

Events recently encountered are in carbon steel piping with system temperatures ranging from 280 to 445 F, system pressure of 500 to 1080 psi, flow of 9 to 29 fps with presence of turbulent flow.

Previously issued generic communications of this subject are: IN 86-106, IN 87-36, IN 88-17, BL 87-01, and GL 89-08.

IN 91-18: High-Energy Piping Failures Caused by Wall Thinning
This information notice alerted licensees to continuing erosion/corrosion problems affecting the integrity of high-energy piping systems and apparently inadequate monitoring programs. The piping failures at domestic plants indicate that, despite implementation of long-term monitoring programs pursuant to Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," piping failures caused by wall thinning continue to occur in operating plants. This IN suggested that recipients review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems.

IN 91-19: Steam Generator Feedwater Distribution Piping Damage
Feedwater distribution piping damage occurred because of thermal stress, cracking, erosion and corrosion. The damage has been attributed to improper design of the feeder ring in CE type steam generators predating System 80 design and in other SGs with similar designs

IN 91-28: Cracking in Feedwater System Piping
Augmented inspection of the feedwater system as part of ISI is effective in identification of cracks in the feedwater lines at PWRs. This IN addresses the issuance of NUREG/CR-5285, "Closeout of IE Bulletin 79-13: Cracking in Feedwater System Piping." The report concludes that (1) the licensees for all of the facilities affected by the bulletin and its supplements have taken the action required by the bulletin, and the

concerns in the bulletin were confirmed, in that cracks were found and corrected at 18 of 54 facilities. Furthermore, the report indicates that some licensees have incorporated augmented inspections of their feedwater lines as part of their inservice inspection programs and recommends that such licensees continue to perform the inspections because these inspections appear to reliably detect degradation in feedwater piping.

IN 91-38: Thermal Stratification in Feedwater System Piping
This IN alerts the addressees of feedwater system piping that could be subject to unexpected and unacceptable movement as the result of thermal stratification. Global thermal stratification results in low-cycle fatigue, pipe movement, and stresses that might not have been considered in the design of the piping system. The low-cycle fatigue identified here is present in long runs of feedwater piping where the temperature difference between the water at the top and bottom of the pipe varies as much as 200F, which is attributed to inadequate mixing.

IN 92-07: Rapid Flow-Induced Erosion/Corrosion of Feedwater Piping
Rapid flow induced erosion/corrosion of feedwater piping in Westinghouse designed steam generators Type D-4, D-5, and E, in which a portion of feedwater is diverted to the upper feedwater nozzles.

The NRC has stated in various generic communications that high velocity flows may cause rapid flow-induced erosion/corrosion in carbon steel piping.

IN 93-20: Thermal Fatigue Cracking of Feedwater Piping to Steam Generators
Thermal fatigue cracking has been observed in feedwater piping at various plants. These failures have been seen in PWRs. The main cause of crack growth appears to be fatigue induced by stress from thermal stratification during cold, low-flow, feedwater injection.

Other contributing factors are high oxygen content, counterbore weld preparation geometry, and thermal conditions during heatup, hot standby, and low-power operation.

Inspection techniques specified in ASME Section XI do not appear adequate to find cracks of this type.

IN 93-21: Summary of Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs
This IN summarizes the NRC observations of the design and implementation of licensee pipe wall thinning and erosion/corrosion programs.

Most problems that licensees have had in implementing erosion/corrosion programs pertain to weaknesses or errors in the following areas:

1. Use of predictive models,
2. calculating minimum wall thickness acceptance criteria per the design code,
3. analyzing results of UT examinations,
4. self assessment of erosion/corrosion program activities,
5. dispositioning components after reviewing the results of the inspection analyses, or
6. repair or replacing components that failed to meet the minimum wall thickness acceptance criteria.

IN 94-63: Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks
IN 94-63 reported instances of boric acid corrosion of makeup pump casing caused by cladding cracks. Cracks of austenitic stainless steel cladding, which caused corrosion and loss of the underlying ferritic steel, were found in both the suction and discharge of the affected pumps. No root cause evaluation was provided.

IN 95-11: Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device
IN 95-11 discussed erosion/corrosion of a condensate line (carbon steel piping) between two feedwater heaters. The condensate line containing the flow-metering device and flow straightener was in the erosion/corrosion program and modeled with CHECMATE, but it was modeled as a straight 16 inch pipe section without any diameter or thickness change.

IN 97-76*: Degraded Throttle Valves in Emergency Core Cooling System Resulting from Cavitation-Induced Erosion During a Loss-of-Coolant Accident*
This IN alerted licensees to potential problems caused by degradation of emergency core cooling system (ECCS) throttle valves in the intermediate-head safety injection pump hot-leg and cold-leg flow paths and in the charging pump(high-head safety injection) cold-leg flow paths during certain loss-of-coolant-accident (LOCA) scenarios. Specifically, the IN addressed cavitation and erosion of throttling valves. Licensees were asked to review information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems.

IN 97-84: RUPTURE IN EXTRACTION STEAM PIPING AS A RESULT OF FLOW-ACCELERATED CORROSION
This information notice alerted licensees to potential generic problems related to the occurrence and prediction of flow-accelerated corrosion (FAC) in extraction steam systems. It was suggested that licensees review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems.

IE Bulletins

BL 75-01, BL 75-01A: Through Wall Cracks in Core Spray Piping at Dresden 2
Take representative samples of pressure retaining welds in austenitic piping in listed piping systems and welds in branch piping runs greater than 2-inch nominal size. Systems include Core Spray, LPCI, Standby Liquid Poison, and Feedwater.

BL 76-04: Cracks in Cold Worked Piping at BWRs
Stress corrosion caused through wall cracking of base metal at bend in 6-inch SS pipe located outside of the drywell.

BL 79-03: Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe
IE Bulletin 79-03 reported that conventional NDE techniques were not adequate to detect centerline lack of weld penetration in longitudinal welds of Type 304 SS pipe manufactured by various vendors. No actions were required if licensees determined that design stresses for components within the system are less than 85% of code allowable. This bulletin is a design related issue and is not an aging management issue.

BL 79-13 REV 0, 1, 2: Cracking in Feedwater System Piping
Cracking of feedwater nozzle-to-pipe welding zones were discovered at various Westinghouse and CE designed plants. These cracks where characterized as "fatigue assisted by corrosion" or "stress assisted corrosion."

All PWRs were asked to perform certain volumetric examination of their feedwater piping systems and report any indication. No indications of cracking were found in B&W designed plants.

BL 79-17: Pipe Cracks in Stagnant Borated Water Systems at PWR Plants
IE Bulletin 79-17 addressed pipe cracks in stagnant borated water systems at PWR plants; this bulletin is related to IN 79-19 on cracking of stainless steel piping reported above. Licensees were required to conduct a review of safety-related stainless steel piping systems to identify systems and portions of systems that contain stagnant oxygenated borated water. For the identified portions, licensees were required to provide information concerning pre-service NDE, inservice NDE results, and water chemistry controls. Plant-specific actions taken in response to IE Bulletin 79-17 were reported to the NRC and all affected locations have been identified and corrective actions were taken.

BL 87-01: Thinning of Pipe Walls in Nuclear Power Plants
Erosion/corrosion of carbon steel pipe walls have been reported in large bore piping systems. Although erosion/corrosion pipe failures have occurred in other carbon steel systems, particularly in small diameter piping in two-phase systems and water systems containing suspended solids, there have been few previously reported failures in large diameter systems with high purity water.

The NRC then requested information concerning utilities programs for monitoring the wall thickness of pipes in condensate, feedwater, steam, and connected high energy piping systems including all safety-related and non-safety-related piping systems fabricated of carbon steel.

BL 88-08: Thermal Stresses in Piping Connected to Reactor Cooling Systems, and Supplements 1, 2, and 3

BL 88-08 requested that licensees review the RCS to identify any connected, unisolable piping that could be subjected to temperature distributions that would result in unacceptable thermal stresses, and take action to ensure piping will not be subjected to unacceptable thermal stresses. Cracking because of unacceptable thermal stresses (i.e., fatigue) is not addressed in the Treated Water Tool but is discussed in the Fatigue Tool (Appendix H).

Generic Letters

GL 79-20: Cracking in Feedwater Lines

The purpose of this generic letter was to request design, fabrication, preservice inspection and inservice operating history of feedwater line in PWRs because of cracks observed in feedwater lines at D.C. Cook units 1 and 2. Leaking circumferential through-wall cracks were identified in the piping heat affected zones of two feedwater nozzle to pipe welds. No aging mechanism was identified at the time this GL was issued.

GL 84-11: Inspections of BWR SS Piping

All SS piping welds in systems operating over 200F are susceptible to IGSCC.

GL 88-01 S1: NRC Position on IGSCC in BWR Austenitic SS Piping

IGSCC is a concern for all BWR austenitic SS piping that is 4-inches or larger and that contains reactor coolant at a temperature above 200F during power operation regardless of ASME classification.

GL 89-08: Erosion/Corrosion-Induced Pipe Wall Thinning

Pipe wall thinning in single and/or multi-phase flow high energy carbon steel systems is widespread. This concern with erosion corrosion was emphasized by this request for information from the sites as to the status of their pipe wall thinning monitoring programs. The NRC has previously issued six Information Notices 86-106- Supplements 1, 2, and 3, 87-36, and 88-17 and Bulletin 87-01 addressing this problem. While the problem is more prevalent among PWRs, it also occurs in BWRs.

Appendix A of NUREG-1344 provides guidelines for effective erosion/corrosion monitoring of carbon steel components and additional insight to this phenomenon. This GL was issued to obtain information from licensees concerning their commitments to put in place formalized procedures or administrative controls to ensure continued long term implementation of its erosion/corrosion monitoring program for piping and components within the licensing basis.

GL 90-05: Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping

This generic letter provides specific guidance to perform non-code repair of ASME code Class 1, 2, and 3 piping. This generic letter does not address aging phenomenon but it provides approved methodology for temporary non-code repair for ASME Code Class 1, 2, and 3 piping.

Summary
A review of NRC generic correspondence shows that a majority of the operating history failures are discussing wall thinning as a result of erosion-corrosion and cracking. The root causes for cracking are not always identified except in those cases where the contaminant was known (e.g., chloride ions). The operating history supports the aging effects discussed in Sections 3.1 through 3.4. The thermal stratification aspects are addressed in Appendix H, Fatigue.

3.7 Summary of Potential Aging Effects

The previous sections discuss various aging mechanisms and their applicability within the bounds of the specific material and environmental conditions covered by this tool. Aging mechanisms that are deemed plausible because conditions exceed established threshold limits have been identified along with the associated aging "effects" (Table 3-2). Programs that are credited with managing aging predominantly focus on these "effects", not on the aging mechanisms themselves.

Table 3-2 Summary of Potential Aging Effects

Materials	*Loss of Material*	*Cracking*	*Reduction of Fracture Toughness*	*Distortion*
Wrought Austenitic Stainless Steels (including weld metals)	Crevice Corrosion Pitting Corrosion	SCC/IGA See App. H for Fatigue MIC	Not Applicable	Not Applicable
CASS	Crevice Corrosion Pitting Corrosion	SCC/IGA See App. H for Fatigue MIC	Thermal Embrittlement applicable if temperatures greater than 482°F	Not Applicable
Nickel-Base Alloys (including weld metals)	Crevice Corrosion Pitting Corrosion	SCC/IGA and PWSCC if temperature above 500°F. See App. H for Fatigue.	Not Applicable	Not Applicable
Carbon Steel, Low-Alloy Steels and Cast Iron	Crevice, Pitting, General, and Galvanic Corrosion, Erosion-Corrosion (Selective Leaching gray cast iron only) MIC	See App. H for Fatigue	Not Applicable	Not Applicable
Copper Nickel Alloys (90-10 and 90-30)	Pitting/Crevice Galvanic, MIC Erosion Corrosion	See App. H. for Fatigue	Not Applicable	Not Applicable
Aluminum Bronze	Crevice/Pitting Selective Leaching Galvanic, MIC Erosion Corrosion	SCC/IGA See App. H for Fatigue	Not Applicable	Not Applicable
Copper Zinc Alloys	Crevice/Pitting Selective Leaching Galvanic, MIC Erosion Corrosion	SCC/IGA See App. H for Fatigue	Not Applicable	Not Applicable
Organic Protective Coatings	Insufficient data to draw conclusion.	Insufficient data to draw conclusion.	Insufficient data to draw conclusion.	Insufficient data to draw conclusion.

4. FLOW DIAGRAM DEVELOPMENT

4.1 Assumptions

The assumptions used to develop the evaluation flow chart are provided below.

1. Although chemistry is maintained within the specifications discussed in Section 2.2, each plant has established impurity threshold limits that may or may not be the same as those identified in the Section 3 tables. When thresholds are exceeded, corrective actions are taken to bring the water chemistry within specifications. Significant chemistry excursions require evaluation prior to continued operation. The ensuing logic diagrams include impurity thresholds and do not assume that contaminants are within those limits established in a water chemistry program. In addition, the flow diagrams and threshold values may be used as guidance for developing lay-up procedures.

2. Crevice corrosion requires some type of crevice (an opening usually a few thousandths of an inch or less in width) to occur. It is unreasonable to expect an evaluator to respond to a question of whether or not a crevice exists within a system or component. The logic, therefore, will assume conservatively that the potential exists for crevices in all components and systems.

3. Pitting and crevice corrosion are similar mechanisms in that crevice corrosion is typically considered to be pitting in a crevice. Pitting corrosion requires oxygen and some form of impurity is also necessary to attack the oxidized surface layer of the material. Crevice corrosion also requires oxygen, however, no other bulk fluid contaminant is necessary. Oxygen alone is sufficient to support the metal dissolution in a crevice. Crevices are a natural place to concentrate contaminants and the tool assumes that crevices may contain contaminants regardless of bulk fluid impurity levels. During shutdown aerated primary coolant can have dissolved oxygen contents above 8 ppm when the reactor vessel head is removed for refueling. However, refueling outages are usually brief, temperatures are low and halogen levels are still controlled to below the threshold values. No pitting or crevice corrosion has been observed in reactor internals under these conditions as a result of extended outages e.g. Three Mile Island. Therefore crevice corrosion is not expected during extended outages.

4. Pitting requires stagnant or slow moving fluid such that contaminants can concentrate on the metal surface. For the purposes of this tool logic, low flow for treated water is defined as <3 ft/sec based on industry experience that shows velocities of 2 - 3 ft/sec keep the impurities from precipitating on the component surfaces.

5. Instances of cracking of sensitized welded joints as a result of exposure to oxygenated borated water have been corrected in accordance with the requirements

of BL 79-17. It is assumed that the damaged joints have been repaired or replaced with low carbon stainless steel.

6. Some aging effects are the result of mechanisms that require the material to be under stresses that are difficult to predict without detailed knowledge of all fabrication, maintenance and operating history. The stress levels necessary to cause these aging effects are also dependent on material type, temperature and fluid environment. It is unreasonable to determine the stress for each application. Therefore, it is conservatively assumed that stresses sufficient to cause these aging effects are present.

7. Primary Water Stress-Corrosion Cracking of non-Class 1 nickel-base alloys is not an active mechanism below 500°F.

8. Thermal embrittlement of cast austenitic stainless steels is not significant at temperatures below 482°F (250°C).

9. It is assumed all conditions that could result in cavitation erosion were corrected during the current term of operation, and therefore cavitation erosion is not an applicable aging mechanism for the extended operating period. An exception to this assumption would be cases where design problem resolution resulted in a change to the Current Licensing Basis (CLB). For example, if the design change includes a new pump design, cavitation erosion may become active because of the new design. Another exception is when cavitation occurs in infrequently operated systems where loss of function may occur in the period of extended operation. In these cases, plant-specific considerations affecting the resolution may need to be addressed in the aging management review.

10. Organic coatings were applied in accordance with the manufacturers requirements.

11. Although MIC is not probable in treated water systems it cannot be categorically excluded due to the potential for contamination and subsequent damage if left untreated. However, MIC is only a potential aging effect for treated water systems where contamination with microbes has occurred. Numerous approaches are available to control or monitor infestation into treated water systems and it is left up to each utility to determine how the potential for contamination is evaluated.

12. The logic is not intended to evaluate out-of-limit conditions. If a significant transient or intrusion has taken place, this condition will have been evaluated during the original license period or will be evaluated upon occurrence during the license renewal period. These conditions are not license renewal issues.

4.2 Overview

The mechanical tools are intended to provide an efficient method to identify applicable aging effects for materials in treated water environments. Implementation of these tools at the various sites will result in the identification of plant equipment and aging effects that must be managed during the period of extended operation. Demonstration of the adequacy of aging management programs to manage these effects is outside the scope of this tool and will be addressed on a plant-specific basis.

Various aging mechanisms requiring different initiating conditions can result in similar aging effects. For example, pitting and crevice corrosion can occur under different environmental and material conditions; however, the resultant aging effect for both mechanisms is a loss of material and subsequent reduction in wall thickness.
Some plant programs such as water chemistry control can be credited with controlling the environment for some systems and/or components whereby conditions do not exist for certain aging mechanisms to occur. However, in order to credit these programs with controlling the environment, it must be assured that this environmental control is carried over into the renewal period.

4.3 Tool Description

Table 3-2 identifies applicable aging effects that require programmatic oversight for the period of extended operation. The list of applicable aging effects, together with the detailed mechanism discussions in Section 3.0 of this document, provides the basis for development of the tool. Figure 1 contains the logic and criteria to evaluate aging effects for wrought austenitic stainless steel, CASS, and nickel-base alloys within treated water systems.

The upper branch of Figure 1 addresses all cracking and loss of material aging effects. The aging mechanisms covered by this logic include crevice corrosion, pitting corrosion, SCC, and IGA. The second branch on Figure 1 provides the logic to determine whether reduction of fracture toughness resulting from thermal embrittlement is plausible. Some aging effects for a given material only occur under elevated temperature conditions, in the presence of contaminants or in stagnant/low flow areas of systems and/or components. PWSCC of nickel-base alloys is not applicable at temperatures below 500°F. The last branch questions the potential for MIC by contamination in the treated Water systems.

The logic for the treated water/carbon, low-alloy steel and cast iron tool is provided in Figure 2. The applicable aging effects include loss of material because of general corrosion, pitting, crevice-corrosion, erosion-corrosion galvanic corrosion and MIC; and loss of material structural integrity because of selective leaching of gray cast iron.

The logic for the treated water/copper alloys tool is provided in Figure 3. The applicable aging effects include loss of material because of galvanic corrosion, pitting/crevice corrosion, erosion-corrosion, and MIC; cracking because of SCC and IGA; and loss of material properties because of selective leaching.

Figure 1 Treated Water/Stainless Steel

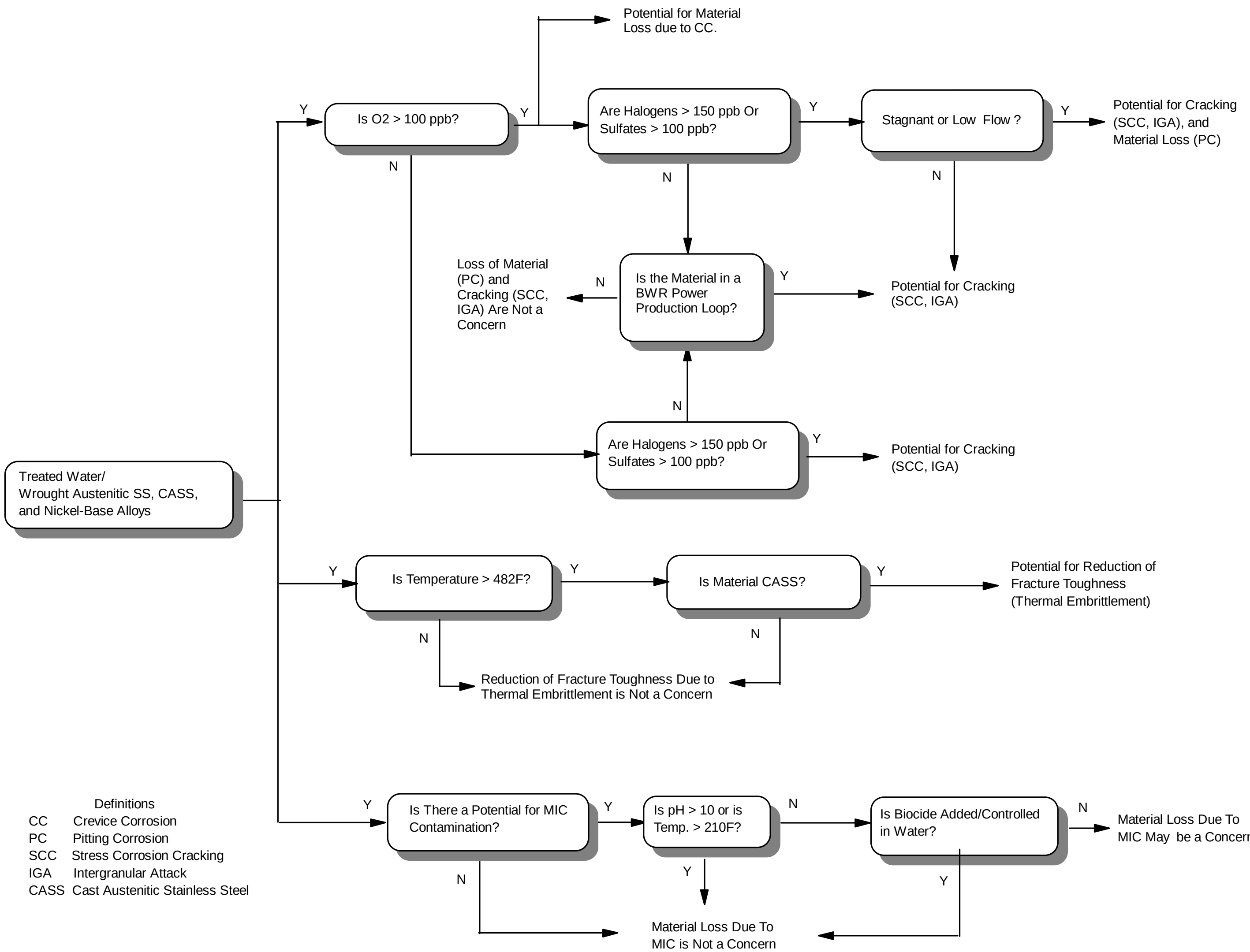


Figure 2 Treated Water/Carbon Steel

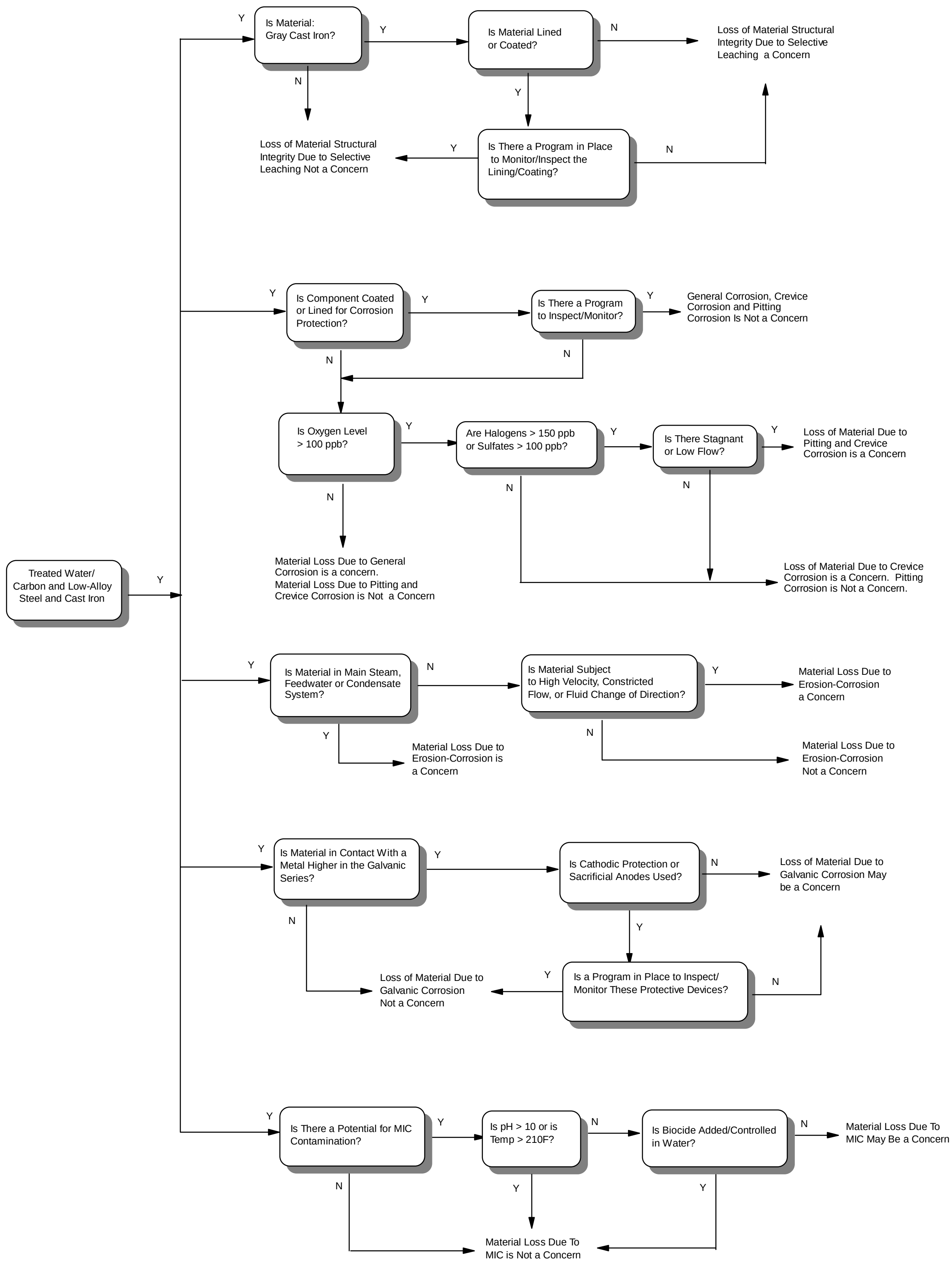
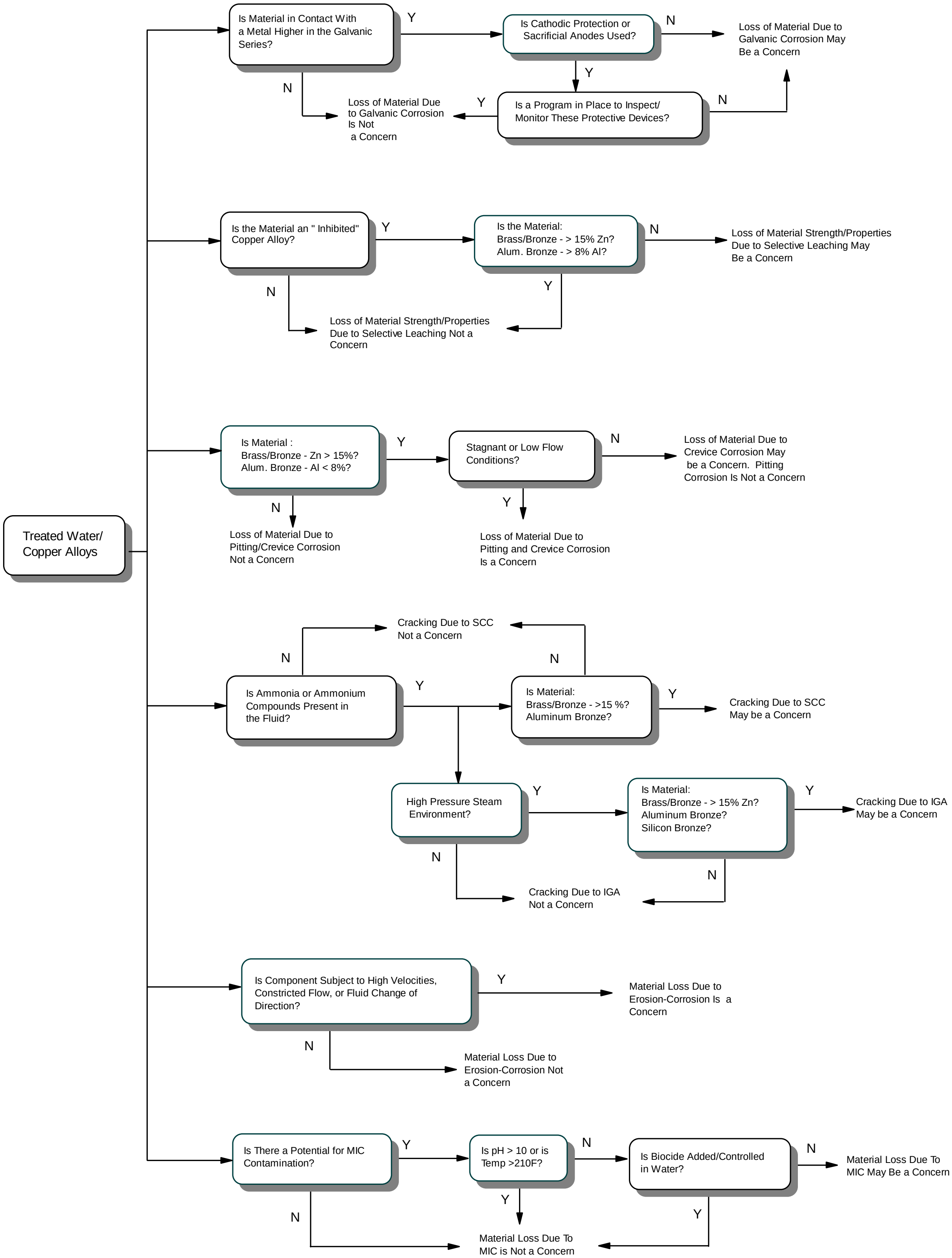


Figure 3 Treated Water/Copper Alloys



5. CERTIFICATION

This appendix is an accurate description of aging effects of carbon steel, stainless steel, and nickel-base alloys in treated water environments prepared for the B&W Owners Group Generic License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

David J. Firth 8/14/99

David J. Firth Date
GLRP Project Manager

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Appendix B--Raw Water

Raw water is defined as water that enters a plant from a river, lake, well, pond, ocean, or bay which has not been demineralized. In general, the water has been rough-filtered to remove large particles and may contain a biocidal additive for control of micro-organisms, zebra mussels, and asiatic clams. Sodium chloride content is below 1000 mg/l for fresh water, above that for saltwater. Raw water is typically used for the condenser circulating water system and the nuclear grade service water system. Other applications include containment cooling, essential area cooling, component cooling water cooling (more prevalent in the BWR industry), diesel generator cooling and jacket water, and decay heat removal cooling. These systems contain a variety of materials including stainless steel, carbon steel, low-alloy steel, copper/nickel alloys, cast iron, copper alloys (brasses, bronzes, copper-nickel, etc.), and galvanized steel.

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1. INTRODUCTION

The Raw Water Tool provides a logic and methodology where selected materials subjected to a raw water environment may be evaluated to identify applicable aging effects. Aging effects considered are cracking, loss of material, reduction of fracture toughness, distortion, and loss of mechanical closure integrity. Loss of mechanical closure integrity is not addressed in the Raw Water Tool, but is treated separately in Appendix F. The Raw Water Tool may be applied when evaluating the pressure boundary integrity of the following components: pipe, tubing, fittings, tanks, vessels, valve bodies and bonnets, pump casings, and miscellaneous process components. The Raw Water Tool is restricted to internal environment and material combinations. Aging effects for materials exposed to external environments are addressed in Appendix E. Evaluation of heat exchangers is performed with the tool contained in Appendix G. Evaluation of fatigue cracking is addressed with the Fatigue Tool in Appendix H.

The materials and environments covered in the Raw Water Tool are discussed in Section 2.0. Aging effects that apply to the material and environment combinations are discussed in Section 3.0. The development of the evaluation flowcharts for the various materials is presented in Section 4.0.

2. MATERIAL AND ENVIRONMENT

This tool provides a logic and methodology where predominantly carbon steel systems subjected to a raw water environment can be evaluated to identify applicable aging effects. These systems are typically high and low pressure service water systems, condenser circulating water systems, reactor building cooling systems, auxiliary service water systems, and fire protection systems. Raw water is also used in some plants to provide residual heat removal and diesel generator cooling. Raw water includes all natural sources such as river, lake, well, brackish, and seawater.

There have been many problems with corrosion in service water systems and resolution of these problems has taken many forms. Some plants have managed the aging of carbon steel service water lines by replacing all formerly carbon steel systems and components with more corrosion resistant materials, such as austenitic stainless steels with low carbon content.

2.1 Materials

The materials evaluated in this tool are: (1) wrought and cast stainless steels, including weld metals and cladding, (2) nickel-based alloys, including nickel-based alloy weld metal, (3) carbon and low alloy steels, including weld metals, (4) cast irons, and (5) copper alloys (brasses, bronzes, copper-nickel).

These materials are identical to those covered by the Treated Water Tool as described in Section 2.0 of Appendix A. The Appendix A discussions on materials and material properties are applicable for this Raw Water Tool also and are not repeated herein.

2.1.1 Protective Coatings

Some of the carbon steel vessels and tanks within the scope of license renewal contain organic protective inner coatings. For example, Plasite is used as an internal coating material for the Borated Water Storage Tanks at some B&W plants. Plasite is manufactured by Wisconsin Protective Coating Corporation and is a water resistant phenolic coating cross linked with epoxy resin and polymerized with an alkaline type curing agent. Other carbon /low alloy steel and cast iron applications, in raw water environments, also can be coated or lined. Metallic underground piping containing salt or brackish water is often concrete lined to provide corrosion protection. Organic based coatings such as coal tar are used in moderately corrosive environments to provide protection for the base metal. This type of coating is common where cast iron is the base metal and raw water is the environment.

Failure of linings/coatings has occurred, however, these failures are typically caused by poor original installation (see discussion for IN 85-024 included in Section 3.6.2 of this Appendix) or improper maintenance, rather than aging of the linings/coatings. The concern resulting from failure of the liner/coating is aging of the underlying base material where failure of the linings/coatings has occurred. Whether the failure results from improper maintenance, inadequate installation or other cause, is not important if it does not result in failure of the base metal pressure boundary function. Since failures have been identified in linings/coatings, it is incumbent on each plant to assess the adequacy of those linings/coatings credited with preventing degradation of the base material.

Not all types of coatings and applications can be included in this mechanical tool logic because of the various types of coatings and the diverse range of applications and environments encountered. This tool allows each utility to credit these various coatings and linings as a means of preventing or minimizing aging effects which would otherwise result from contact of the base metal with the fluid environment. However, if crediting the various linings and coatings with aging effects management, the lining/coating integrity must be assured. This tool requires verification of the liner/coating integrity. Where various plant programs or inspections are credited with assuring the lining/coating integrity, any such programs should be continued through the license renewal period and included as license renewal “effective programs.”

2.2 Environment

Raw water consists of all natural sources of raw water which includes; river, lake, brackish, sea and well water. Raw water is naturally oxygenated and contains varying amounts of impurities (e.g. chlorides, sulfates). Microorganisms can cause microbiologically influence corrosion. Most raw water is rough filtered to remove large particles and is generally treated with biocide to control microorganisms and macroorganisms. Chlorides are often added to raw water as a biocide which increases the potential for IGA, SCC, pitting, galvanic and crevice corrosion.

Many of the aging effects discussed within this mechanical tool require some form of contaminant (oxygen, chloride, ammonia, etc.) to become a significant aging concern. Raw water is a harsh environment and, for the purposes of this Raw Water Tool, is assumed to contain contaminant levels which are sufficiently high to promote these aging mechanisms. Even well water can contain levels of natural contaminants such as calcium, iron, sulfate, etc., and when additional plant water treatments are applied, can result in an aggressive environment.

3. AGING EFFECTS

The Raw Water Tool addresses aging effects that result from age-related degradation mechanisms. Where specific mechanisms are not applicable under the environmental and material conditions covered by this tool, justification is provided for a "not applicable" determination. For effects that are applicable, a detailed discussion of the necessary environmental conditions is included. Aging effects discussed below are loss of material, cracking, reduction of fracture toughness, and distortion. When one or more of the aging mechanisms is determined to be plausible then the associated aging effects are assumed to be applicable for the period of extended operation.

In many instances liners or coatings are applied to shield materials from various degradation mechanisms. This aging effects tool considers the effect of the fluid environment on the base material, however, it acknowledges that liners and coatings are used to protect the base material from aging effects of the fluid. The accompanying tool logic allows each utility to credit these coatings and liners with minimizing the potential for base material aging effects when the liner/coating integrity is verified for the extended period of operation.

3.1 Loss of Material

Aging mechanisms that can lead to loss of the metallic materials listed in Section 2.1 are general corrosion, selective leaching, galvanic corrosion, crevice corrosion, pitting corrosion, erosion and erosion-corrosion, microbiologically-influenced corrosion, and wear. The applicability of each aging mechanism is discussed in Sections 3.1.1 through 3.1.9.

3.1.1 General Corrosion

General corrosion is the result of a chemical or electrochemical reaction between a material and an aggressive environment. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup [2]. At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are required for the corrosion of iron. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any practical extent [3]. Carbon, low-alloy steels and cast iron are susceptible to general corrosion in systems using raw or untreated waters. Where general corrosion is in many cases predictable and can be accounted for by a corrosion allowance, pitting and crevice corrosion, on the other hand, are more unpredictable [3, pg. 40] and a corrosion allowance may be more difficult to calculate from a theoretical basis. However, trending of observed corrosion rates at each site can be used to estimate the remaining life of the piping. Because of the uncertainty involved in determining whether corrosion rates are within the bounds of corrosion allowances, this tool logic identifies general corrosion as an applicable aging mechanism for susceptible materials where oxygen and moisture may be present. This does not prevent utilities from crediting corrosion allowances as a means of managing this aging effect, however, it is not appropriate to generically exclude this aging effect based on corrosion allowances.

The logic also provides for lined or coated components. When responding to the coating/lining question, the evaluator must ensure that the coating/lining is adequate to protect against the aging mechanism under consideration. Also, programs that provide for inspection of linings or coatings should consider the accessibility of the component (e.g. buried or embedded piping).

Since raw water is sometimes used in fire protection systems, the following information is presented from Reference [21]. The corrosion and scale buildup of metal sprinkler pipe is primarily a function of the corrosiveness or aggressiveness of the water, the ambient environmental conditions, the frequency of the introduction of fresh oxygen through system flushes, and the pipe material. Chloride and chloride containing ions are the most common cause of pitting. The Federal Emergency Management Agency (FEMA) report references a Battelle Laboratories study in which 56 specimens were taken from 41 installations located in various parts of the country for corrosion testing to predict probable performance. Since fire protection systems are infrequently used, these systems contain stagnant water for most of their lives. During system flushes, fresh water containing oxygen is introduced. The discussion implies the oxygen is quickly used up to corrode the pipe and, once consumed, no significant corrosion occurs until the next system flush. The report further states that the corrosion forms a protective layer that retards additional pitting from occurring during subsequent flushes. The report concludes that on the basis of examining the schedule 40 steel pipe specimens and extrapolation of the results to light-wall steel pipe, it can be estimated that the light-wall pipe would provide satisfactory performance in most sprinkler systems up to and exceeding 100 years. Each plant may want to consider the applicability of the Battelle study and determine if their operation of the fire system would result in a lower expected rate of corrosion due to the depletion of oxygen in the stagnant portions of the piping.

Stainless steel materials which contain 12% chromium have excellent resistance to general corrosion for all fluid applications except raw water. The chloride content of the water affects the corrosion of stainless steel in raw water applications. However, testing has shown that local pitting is approximately 200 times more severe than general corrosion for Type 304 stainless steel in a flowing seawater environment (50 mil vs. 0.25 mil) [13,14]. Nickel-base alloys have excellent resistance to corrosion in most environments. In a seawater environment, the combination of chloride and fouling deposits can produce severe localized attack. This attack is predominantly in the form of crevice/pitting corrosion formed. Therefore for the purposes of this tool, general corrosion of stainless steels will not be a significant aging mechanism since the dominant failure mode would be from local pitting rather than from loss of wall thickness because of uniform general corrosion.

Copper alloys are used when resistance to general corrosion is required. These alloys are used in atmospheric, fresh and salt water in place of other more susceptible metals such as carbon steel or cast iron [1]. In the presence of ammonia many copper alloys exhibit increased corrosion rates, however, this is primarily in the form of selective leaching which is discussed separately. General corrosion is not considered an aging mechanism for copper alloys in a raw water environment.

3.1.2 Selective Leaching

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Dezincification is the usual form of corrosion for susceptible copper alloys in prolonged contact with waters high in oxygen and carbon dioxide, and most often is associated with quiescent or slowly moving solutions. Copper-zinc alloys containing greater than 15% zinc are susceptible to selective leaching, while copper alloys with a copper content in excess of 85% resist dezincification. Yellow brass (30% zinc and 70% copper) and Muntz metal (40% zinc and 60% copper) are both susceptible to selective leaching. The addition of small amounts of alloying elements such as tin, phosphorus, arsenic and antimony also inhibit dezincification [13, 5]. The addition of 1% tin to brass, for example, decreases the susceptibility to selective leaching [13]. Naval brass is essentially an inhibited Muntz metal produced by the addition of 0.75% tin to the 40% zinc and 60% copper compound.

There are two general types of dezincification, uniform attack and localized plug attack. Slightly acidic water, low in salt content and at room temperature, is likely to produce uniform attack, whereas neutral or alkaline water, high in salt content and above room temperature, often produces plug-type attack. In both types of dezincification the zinc ions stay in solution, while the copper plates back on the surface of the brass. The dissolved zinc can corrode slowly in pure waters by the cathodic ion reduction of water into hydrogen gas and hydroxide ions [5]. For this reason, dezincification can proceed in the absence of oxygen. The rate of corrosion, however, is increased in the presence of oxygen. This process occurs in clean water with no additional contaminant required for initiation [5].

Aluminum bronzes containing greater than 8% aluminum are also susceptible to de-alloying of the aluminum in a similar manner to the dezincification of brass [5]. Aluminum brasses are used to prevent impingement attack where turbulent high velocity saline water is the fluid. These alloys form a tough corrosion resistant protective coating due to the buildup of aluminum oxide. Proper quench and temper treatments for some of the aluminum bronzes produces a tempered structure that is superior in corrosion resistance to the normal annealed structures. This degradation effect has been noted specifically in acid solutions, however, it was also noted that massive effects occurred where the solution contained chloride ions [5]. Unless they are inhibited by adding 0.02 to 0.10% arsenic, aluminum brasses should be considered susceptible to selective leaching.

Gray cast iron can also display the effects of leaching particularly in relatively mild environments. This process initiates with selective leaching of the iron or steel matrix from the graphitic network. The graphite is cathodic to iron, providing a galvanic cell. The iron is dissolved, leaving a porous mass consisting of graphite, voids, and rust. If the cast iron is in an environment that corrodes this metal rapidly (e.g., saltwater), uniform corrosion can occur with a rapid loss of material strength which can go undetected as the corrosion appears superficial [5].

3.1.3 Galvanic Corrosion

Galvanic corrosion occurs when materials with different electrochemical potentials are in contact in the presence of a corrosive environment [5]. The rate of galvanic corrosion is affected by the relative size of the anode to cathode. The material with the lower potential (higher on galvanic series) is the anode and it sacrifices to the cathode. If the anode is appreciably larger than the cathode, then the galvanic corrosion rate is slow. Conversely, if the anode is much smaller than the cathode, then the galvanic corrosion rate can be very large in the presence of moisture and water.

Components within raw water systems may exhibit galvanic corrosion if carbon steels, low alloy steels or cast iron materials are in contact with wrought austenitic stainless steel, CASS or nickel-base alloys. (Cast iron and carbon steel are grouped together in the galvanic series chart and will, therefore, demonstrate similar susceptibility to this aging effect.) Galvanic corrosion can occur if cladding or organic protective internal coatings on tanks are flawed such that dissimilar metals, which are electrically connected, are exposed to a corrosive environment. Galvanic corrosion may also be a concern at raw water system interfaces where stainless steel piping connects to systems using carbon steel, low alloy steel or cast iron fittings and piping. In these instances, dissolution of the ferritic materials would occur preferentially since the more corrosion resistant material (i.e., stainless steel or nickel-base alloy) acts as the cathode [5]. Therefore, wrought austenitic stainless steel, CASS and nickel-base alloys are not susceptible to loss of material because of galvanic corrosion.

Generally the effects of galvanic corrosion are precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). The raw water/carbon steel combination is usually found in service water systems and condenser circulating water systems. In many plants, the components in these systems have needed repair or replacement because of corrosion. In many cases, the replacement material is stainless steel. Where cast iron is used in raw water systems and is in contact with dissimilar metals, design features are typically included to control the rate of corrosion. Heat exchangers, for example, may have sacrificial anodes and/or coatings where there is contact between dissimilar materials. It is important in any aging management program to assure that these design features are assured through the license renewal period (i.e. periodic sacrificial anode replacement and coating verification).

Copper alloys are in the middle of the galvanic series with steel, alloy steel and cast iron being more anodic (or active) and the stainless steels, nickel alloys and titanium being more cathodic (or passive). When coupled with the more anodic materials such as cast iron or carbon steel, the copper alloys would exhibit reduced corrosion effects, whereas the cast iron or carbon steel would tend to exhibit increased corrosion. Conversely, when coupled to the more cathodic materials such as stainless steel, titanium or graphite, the copper alloys would demonstrate an increased susceptibility to corrosion [5,13].

In summary, galvanic corrosion can occur in a corrosive environment where materials distant on the galvanic series chart are in contact. Corrosion of the material with the lower potential can occur, the corrosion rate dependent on the difference between the electrochemical potentials of the two materials. The fluid environment is a factor in determining the electrochemical potentials. Salt water is a more corrosive environment than treated water and the electrochemical potential differences between materials is typically much higher in salt water. Carbon steels, low-alloy steels and cast irons that are in contact with stainless, CASS, or nickel-base alloys (i.e., electrically connected) and are subjected to raw water may be susceptible to galvanic corrosion. Copper alloys are also susceptible when coupled to a more anodic stainless steel, nickel-base alloy, titanium or graphite.

There are five major methods of eliminating or significantly reducing galvanic corrosion: 1) Selecting dissimilar metals that are as close as possible to each other in the galvanic series. 2) Avoiding coupling of small anodes to large cathodes. 3) Insulating dissimilar metals completely wherever practicable. 4) Applying coatings and keeping them in good repair, particularly on the cathodic member. 5) Using a sacrificial anode - that is, coupling the system to a third metal that is anodic to both structural metals.

3.1.4 Crevice Corrosion

Crevice corrosion occurs in crevices or shielded areas that allow a corrosive environment to develop within the crevice. The nature of crevices especially for those very small in size is such that low flow or stagnant conditions can exist in the crevice regions even under system flowing conditions. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads where contaminants can concentrate [5]. Crevice corrosion can occur in the secondary or auxiliary systems in crevices, other areas of stagnancy, and areas of deposit buildup. In addition to stagnant conditions in the crevice, an oxygen content in the fluid above 100 ppb is required to initiate and perpetuate crevice corrosion [6]. Although the oxygen content in crevices can differ significantly from the bulk fluid oxygen levels due to oxygen depletion, etc., a bulk fluid oxygen level to sustain the chemical reaction is necessary for the continued corrosion in the crevice [5]. Carbon steels, low-alloy steels, cast iron, stainless steels, nickel-base alloys and copper alloys are all susceptible, to some degree, to crevice corrosion [13]. The effect of temperature on crevice corrosion is difficult to predict and no simple relationship has been found between temperature and crevice attack in raw water type environments [15].

Crevice corrosion is a potential aging mechanism for carbon and low-alloy steels in an oxygenated raw water environment and where the crevice is subjected to stagnant or low flow conditions [6]. Cast iron and carbon steel undergo the same dissolution reaction [5], therefore, cast iron (in its plain form) is considered to have the same potential for crevice corrosion as carbon and low alloy steel.

Crevice corrosion of copper alloys is a result of oxygen depletion in the crevices such that crevice metal is anodic relative to the metal outside the crevice which is in an oxygen-bearing environment [13]. Crevices are present throughout piping and equipment at connections, discontinuities in material, tube to tubesheet interfaces, etc. Corrosion susceptibility is increased in these areas because of the crevice itself and the buildup of foreign objects or debris such as dirt, pieces of shell, or vegetation [13]. It can also result from the accumulation of rust, permeable scales or deposit of corrosion products at the crevice location. Another form of crevice corrosion can occur at a gas to fluid interface. This specific form of crevice corrosion is commonly called water-line attack as the corrosion occurs just below the water line [13]. Copper zinc alloys with greater than 15% zinc content exhibit high resistance to pitting/crevice corrosion whereas copper zinc alloys with less than 15% zinc are susceptible [13]. Aluminum bronze alloys with greater than 8% aluminum are also highly susceptible to pitting. When the aluminum content is greater than 8%, the aluminum is present in what is referred to as the “alpha-beta” phase, which is much less resistant to corrosion than the “alpha” phase aluminum present in bronzes containing less than 8% aluminum. The copper nickel alloys have also demonstrated susceptibility to pitting/crevice corrosion in aqueous environments [5,13].

3.1.5 Pitting Corrosion

Pitting corrosion usually affects passive metals by attacking passive films in localized areas. Pitting corrosion occurs in most commonly used metals and alloys including carbon and stainless steels as well as in many copper alloys [3, 13]. Once a pit penetrates the passive film, galvanic conditions occur because the metal in the pit is anodic relative to the passive film. Pitting corrosion rates are very unpredictable. They can initially corrode at aggressive rates, then when corrosion by-products build up and the oxygen is starved, the corrosion rate can slow down to almost zero. With stagnant or low flow conditions, impurities such as halides remain in the pit and dissolution of the metal continues. Pitting corrosion can be inhibited by maintaining an adequate flow rate, thus preventing impurities from adhering to the material surface [3]. Low flow for raw water in a carbon steel system is defined to be < 3 fps [4]. For brackish or sea water in a stainless steel system, the low flow threshold is 5 fps [3, 16]. Most pitting is associated with halide ions, with chlorides, bromides, and hypochlorites being the most prevalent ions[5].

Stainless steels and nickel-base alloys are particularly susceptible to pitting attack because of the passive nature of these alloys. Any localized attack tends to progress rapidly at the point of attack. The localized pitting points are small anodic (active) areas that form an active-passive electrolytic cell when connected to the much larger cathodic (passive) area. Pitting proceeds when the oxygen concentration in the surrounding area serves as a depolarizer when compared to the oxygen depleted area of the pit [13]. In seawater, the high chloride content and other contaminants increase the corrosion rate. Although not totally impervious to pitting, molybdenum bearing stainless steels have greatly increased pitting resistance over stainless steel with no molybdenum. Of the nickel-base alloys, Hastelloy 276, Inconel 625 are virtually immune to attack while Hastelloy G, Incoloy 825, Monel 400 and Monel K-500 demonstrate excellent resistance [13].

Pitting is an applicable aging mechanism for copper alloys as with most commercial metals. This corrosive mechanism can occur either as localized attack, or generally over the entire surface. Localized attack takes the form of various shapes and sizes and are typically concentrated at on surface locations at which the protective film has been broken, and where non-protective deposits of scale, dirt or other substances are present [13]. General pitting attack takes the form of a roughened and irregular appearance over the entire material surface. Pitting and crevice corrosion are similar corrosion mechanisms with crevice corrosion sometimes considered localized pitting in a crevice. Where crevice corrosion occurs in crevices that can be stagnant even under flowing conditions, pitting requires either low flow or stagnant conditions to sustain the corrosion reaction [13]. While copper alloys are generally resistant to pitting and crevice corrosion, copper zinc alloys with less than 15% zinc are susceptible. Aluminum bronze with greater than 8% Al., and copper nickel alloys are considered susceptible to pitting in stagnant or low flow conditions.

3.1.6 Erosion and Erosion-Corrosion

Erosion

Erosion is the loss of material induced by flowing fluid. Raw water systems are particularly susceptible to this mechanism since they usually contain large amounts of particulate. This particulate in the fluid stream can impinge upon the surface of the metal and result in a loss of material at that point. Regions that may be susceptible to this type of erosion include locations that have high fluid velocities and flow discontinuities such as elbows and T-type joints/fittings. Lined or coated components are susceptible to damage of the lining/coating under these conditions which results in corrosion potential for the base material in the eroded locations. Carbon steel, low-alloy, cast iron, wrought austenitic stainless steel, CASS, copper alloys and nickel-base alloys are all susceptible to erosion [1, 5, 13].

Erosion-Corrosion

Erosion-corrosion is a mechanism whereby fluid flow erodes or dissolves away the protective oxide or passive film of a metal, causing increased corrosion and reoxidation. The process repeats itself over time, causing general thinning of the material due to material loss. Flow rates less than 6 ft/sec will not cause erosion-corrosion of carbon and low-alloy steels [7]. Temperature, pH, and oxygen influence erosion-corrosion in carbon and low-alloy steels. Higher pH levels lead to decreased erosion-corrosion [2,5]. A threshold value of pH>10 can be established based on data presented in Reference 5 [see pg. 94]. Erosion-corrosion rates are greatest at temperatures of 250 to 340^{o}F and decrease rapidly above and below this temperature range [1]. The 6 fps threshold in Reference 7 involved high temperature water and an absolute velocity threshold may not be appropriate for raw water applications. Design handbooks often suggest velocities in the 8-10 fps range for water supply systems [22]. The amount of abrasives in the water is a key factor affecting the potential for erosion-corrosion. The amount of abrasives in the water is a site dependent variable, and each plant may want to choose a velocity threshold based on their site-specific conditions.

Carbon steels, low alloys and cast iron are susceptible to erosion-corrosion. Piping layouts such as elbows, small radius of change of direction, and branch connections of 90-degrees are most susceptible to flow-induced erosion-corrosion [13]. Local deposition and macrofouling can produce localized areas of high velocity or turbulence [12]. Vulnerable locations need to be evaluated for each individual plant [8]. A review of the NPRDS data shows a significant number of failures (approximately 12.7%) reportedly due to erosion-corrosion (See Section 3.6.1). A closer review of some of this data shows a number of these failures to be clearly a result of cavitation or particle impingement. Discussions with the plants' systems engineers also support the occurrence of these types of failures in the service water systems whether they be erosion-corrosion, impingement, or cavitation. Therefore, erosion or erosion-corrosion can be a significant aging mechanism for carbon steel in raw water systems.

Austenitic stainless steels are immune to erosion/corrosion because the high chromium content (>12%) forms a tenacious, tough, passive film that is resistant to erosion of single phase and two phase flows [13]. Therefore, erosion-corrosion is considered not applicable for stainless steels in raw water environments.

Copper alloys are used extensively in nuclear plant raw water environments (particularly in heat exchanger applications) due to their overall corrosion resistance in harsh aqueous environments [13]. While no copper alloys are immune to the effects of erosion corrosion, numerous copper alloys are available that are highly resistant [13]. Aluminum bronzes containing 5% to 12% aluminum, aluminum brasses and the copper nickel alloys demonstrate superior resistance to impingement corrosion. The excellent erosion corrosion resistance of these copper alloys is partly due to their insolubility in seawater and also because of the formation of a corrosion film on the surface that is highly resistant to erosion in turbulent flowing seawater environment. However, even these highly resistant alloys are not immune to erosion corrosion and exhibit erosion corrosion rates at high velocities similar to those exhibited by carbon steel and cast iron under similar conditions [5]. The 6 ft/sec velocity threshold identified above for carbon steel should also be applied to the copper alloys. The copper alloys should be considered susceptible to erosion corrosion where high velocities, constricted flow or change in fluid direction occurs.

Cavitation-Erosion

Cavitation erosion has occurred in service water systems, generally due to the improper operation of pumps and valves [12]. This mechanism can also occur in stationary components such as orifice or pressure reducing devices that were improperly designed. Cavitation is considered a design problem which is detectable and correctable long before the license renewal period. Examples include inadequate net positive suction head (NPSH) for pumps, too high a turndown for valves, or operating at below vapor pressure for any component. Therefore, cavitation erosion is not considered an applicable aging effect for the period of extended operation.

3.1.7 MIC

Microbiologically-influenced corrosion (MIC) is corrosive attack accelerated by the influence of microbiological activity. MIC usually occurs at temperatures between 50 and 120F, however, microbes can withstand a wide range of temperatures (15 to 210^{o}F) [17]. These organisms have been observed in mediums with pH values between 0 and 10.5 and under pressures up to 15,000 psi [13]. Due to the number of different microorganisms involved in MIC and the wide array of environments that can support the growth of microbiological activity, resultant corrosion can be caused by many different chemical reactions or material property changes. Typically, MIC is manifested as a localized loss of material similar to pitting type corrosion. The different types of microbes can grow with or without oxygen and can thrive in many chemical environments. Some anaerobic organisms reduce sulfate to sulfide ions which influences both anodic and cathodic reactions on iron surfaces [7, 13]. Several forms can metabolize NO_3, which is used widely as a corrosion inhibitor. These species produce many different byproducts which can accelerate corrosion of certain alloys. Some aerobic organisms produce sulfuric acid by oxidizing sulfur or sulfur-bearing compounds. The ammonium producing variety will increase the corrosion of copper alloys [13].

In general, microbiological organisms disrupt the metal's protective oxide layer and produce corrosive substances and deposit solids that accelerate the electrolytic reactions of corrosive attack, generally in the form of pitting or crevice corrosion. MIC is facilitated by stagnant conditions, fouling, internal crevices, and contact with untreated water from a natural source. Laid up lines, stagnant portions of systems containing raw water, and untreated connected systems are all susceptible. The lack of treatment during stagnant conditions such as outages and equipment down time, for systems normally treated, is a major problem at plants [13].

Nearly all nuclear plant materials of interest can be affected [11, 13]. MIC has deteriorated iron, steel, stainless steel, copper and copper alloys. In austenitic stainless steels, MIC preferentially attacks welds and weld heat-affected zones (HAZs) for reasons as yet unclear. In the other materials covered by this tool, MIC does not show such preference [13]. Titanium and nickel chrome alloys at this time appear to show promise of MIC resistance, however, the data is insufficient to completely rule this aging effect out for those materials.

There are several approaches that can be used to control MIC. The literature indicates that a high pH (>10) will inhibit MIC and that MIC cannot survive high temperature (>210^{o}F). In some cases raising the pH may be an effective method of prevention and is included in this tool logic, however, this approach in raw water systems would not appear to be cost effective. The most cost effective and efficient method is to treat the raw water with a biocide such as ozone, chlorine, etc. Ozone has been demonstrated to totally eliminate microorganisms with a 0.2 ppm concentration. Where ozone is not appropriate, a chlorine concentration of .5 ppm has been demonstrated to be effective [13]. (Chlorine obviously may not be the chosen treatment in some systems because it promotes stress corrosion cracking and pitting of stainless steel). Maintaining fluid flow in a systems is another approach to controlling MIC. This is not as effective as using a biocide for a number of reasons. Although fluid velocities less than 2-3 ft/sec are most commonly associated with MIC, build up of slime and bacteria in crevices can lead to MIC, despite high flow rates [17]. Raw water systems are not operated continuously and, therefore, other means of MIC prevention during equipment and system down time must be employed. For the purposes of this tool, raising the temperature and/or maintaining fluid flow are not used as logic to prevent MIC. Raising the pH is assumed in the logic to control MIC.

3.1.8 Wear and Fretting

Wear results from relative motion between two surfaces, from the influences of hard, abrasive particles or fluid streams, and from small, vibratory or sliding motions under the influence of a corrosive environment (fretting) [2]. Loss of material from erosion and erosion/corrosion is discussed in Section 3.1.6. Wear and fretting of external surfaces are addressed in Appendix E. The following discussion explains why these mechanisms do not apply to this tool.

3.1.8.1 Wear

Wear can result from the movement of a material in relation to another material. This can occur during a component's performance of active functions of a component which are not addressed by this tool (e.g., pump and valve operations). General wear is, therefore, not applicable for the equipment covered by these tools.

3.1.8.2 Fretting

Fretting is caused by small amplitude vibratory motion [e.g., flow induced vibration (FIV)] which results in removal of material between two contacting surfaces. With the exception of heat exchangers, and external surfaces of mechanical equipment, passive components in the raw water/carbon steel and stainless steel systems are not susceptible to this mechanism. Heat exchangers and external surfaces are evaluated separately in Appendices G and E respectively. This mechanism is, therefore, not considered applicable in this tool.

3.1.9 Fouling

Aqueous macroorganisms such as barnacles, mussels, clams, algae, and others found in fresh and salt water. These macroorganisms may prevent the performance of intended functions as a result of flow blockage, degradation of heat transfer, fouling, and loss of material caused by crevice corrosion. The attached organisms create crevices which promote locations for crevice corrosion.[5] Flow blockage is an issue that is under the review of the NRC and industry. The user of this document should review the regulatory correspondence and developments with respect to treatment of flow blockage as an aging affect issued subsequent to this document. Generic Letter (GL) 89-13 and acceptance of the GL 89-13 programs by the NRC may be sufficient reasoning to preclude macroorganisms as an aging problem. The detection and correction of these effects are required by GL 89-13. See Section 3.6.2 for a discussion of GL 89-13 requirements. In certain cases, this problem could be perceived also as routine maintenance since periodic cleaning is necessary to ensure unimpeded flow and absence of crevice attack. Silting and corrosion product build-up is considered in the same category.

3.2 Cracking

3.2.1 Hydrogen Damage

Hydrogen damage results from the absorption of hydrogen into the metal. It includes the degradation mechanisms of hydrogen blistering and embrittlement [2, 5]. Hydrogen damage usually manifests itself as hydrogen embrittlement in high strength steels and hydrogen blistering in low strength steels. Hydrogen blistering has been seen in low strength carbon and low-alloy steels in the temperature range of 30 to 300^{o}F [9]. Corrosion and the application of cathodic protection, electroplating, and other processes are major sources of hydrogen in metals. Hydrogen blistering is most prevalent in the petroleum industry, in storage tanks and in refining processes [5]. A review of the failure data for PWR and BWR raw water systems show no evidence of hydrogen blistering; therefore, it is considered not applicable for carbon steels in raw water systems.

Another term for hydrogen embrittlement is sulfide stress cracking if the cracking is due to the presence of hydrogen sulfide. A few ppm of absorbed hydrogen can cause cracking [5]. At yield strengths of less than 120 ksi for carbon, low-alloy steels and cast iron, concern regarding hydrogen cracking is alleviated except when the material is temper embrittled [2]. Since the yield strength of most of the piping and components in the raw water applications is on the order of 30 to 45 ksi, hydrogen embrittlement is considered not applicable for carbon steels. The yield strength of even the hardest cast irons is less than 100 ksi, with plain cast irons in the same range as that noted above for the carbon and low alloy steel applications and therefore cast irons are not susceptible to hydrogen embrittlement. Copper alloys also have low yield strengths and are considered not to be susceptible to hydrogen embrittlement. Only tough pitch copper alloys in a reducing atmosphere are susceptible to hydrogen embrittlement [13]. The commonly used copper alloys, including those covered by this tool, are deoxidized and are not susceptible to SCC.

In most cases, austenitic stainless steels are immune to hydrogen damage although nickel-base alloy may be somewhat susceptible [2,3]. It is thought that primary water stress corrosion cracking may be caused by a form of hydrogen damage. The industry literature has not identified any incidents of hydrogen damage to stainless steels or nickel-base alloys. Therefore, hydrogen damage is considered not applicable to stainless steels or nickel-base alloys in raw water.

3.2.2 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a type of corrosive attack that occurs through the combined actions of stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. Highly stressed materials require less corrosive environments and highly corrosive environments require less stress to initiate and propagate cracking. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. SCC is either intergranular stress corrosion cracking (IGSCC) or transgranular stress corrosion cracking (TGSCC), depending upon the crack path.

IGSCC is cracking along the grain boundaries of the material. It is typically associated with materials containing excessive grain boundary carbide precipitation or impurity segregation. Although IGSCC usually occurs in fluid with high dissolved oxygen (>100 ppb), it can occur in a low oxygen environment. Preferential grain boundary precipitation of carbides in austenitic stainless steels and nickel-base alloys can lead to a localized depletion of chromium in the vicinity of the grain boundary. This is known as sensitization and is one of the mechanisms that promotes IGSCC.

Grain boundary segregation of impurities such as phosphorous, sulfur, and silicon is another mechanism believed to promote IGSCC. It can produce a grain boundary chemical composition with a significantly different electrochemical potential from that of the bulk alloy composition. The effect of this electrochemical potential difference is an increase in corrosion susceptibility at the grain boundaries.

TGSCC is characterized by cracks that propagate through (or across) the grains of the material. Numerous metallurgical factors, such as crystal structure, grain size and shape, dislocation density and geometry, and phase composition, affect TGSCC. It can occur in austenitic, duplex, martensitic and precipitation hardened stainless steels subjected to chlorides and oxygenated environments and in the presence of caustic solutions.

Intergranular attack (IGA), also known as intergranular corrosion, is similar in some respects to SCC; however, it is distinguished from SCC because stress is not necessary for it to proceed. IGA is characterized by deterioration of grain boundaries without appreciable attack of adjacent grains. That is, the rate of attack on grain boundaries greatly exceeds that of the matrix material. Generally, materials and conditions that are susceptible to intergranular stress corrosion cracking will also be susceptible to IGA. Silicone bronze is a material that is susceptible to IGA yet is not susceptible to SCC. Stresses in materials are generally categorized as either applied or residual stresses. Applied stresses are the result of operating history and loadings, or stresses applied during fabrication as a result of bolting, riveting, welding, bending, etc. Residual stresses are those stresses resulting from the actual fabrication of the material and include cold working, tube drawing, spinning, tooling, etc. [13]. These stresses are very difficult to ascertain for any given component or material and this detailed evaluation and identification of applied and residual stresses are beyond the scope of this tool. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and the environment. Increasing the stress tends to decrease the time for cracking to occur and, together with the specific temperature and environment to which a material is exposed, makes it extremely difficult to identify a minimum threshold stress level for SCC. Therefore, it is assumed that all austenitic stainless steels, nickel-base alloys, and copper alloys evaluated using these tools contain stresses sufficient to initiate SCC if subjected to a corrosive environment. A discussion of the susceptibility of austenitic stainless steels, nickel base alloys, copper alloys, and carbon steels to SCC or IGA in a raw water environment is provided below.

SCC of Wrought Austenitic Stainless Steel and CASS

Austenitic stainless steels with a sensitized microstructure are particularly susceptible to SCC in oxidizing environments, although sensitization is not a requirement. The critical stress levels required to cause cracking in a sensitized structure can be quite low; residual stresses are often sufficient. A sensitized microstructure does not guarantee that SCC will occur, nor does an unsensitized microstructure guarantee that SCC will not occur. At temperatures below 200^{o}F, intergranular stress corrosion cracking (IGSCC) is not a concern for austenitic stainless steels in an oxidizing water environment in the absence of chlorides and sulfates. In the presence of chlorides, IGSCC in stainless steel can occur at room temperature [2].

The logic tool for raw water/stainless steel conservatively offers no threshold or exclusion values for SCC. Therefore for the generic tool, all stainless steels in raw water systems will have the potential for cracking. For those plants that may have an abundance of information relating to material and water chemistry and that may want to evaluate SCC more rigorously on a plant-specific basis, the following information is presented.

The literature refers to a general rule of thumb for a threshold temperature for the onset of SCC in water of 140^{o}F [27]. It is emphasized that this threshold temperature applies only to austenitic stainless steels that are not sensitized and are in near-neutral waters of moderate to low chloride content (moderate to low was not defined). Low pH, concentrated chlorides or sensitization could lead to failures at temperatures significantly below the 140^{o}F threshold. Data from the electric power industry show that sensitized Type 304 and Type 316 stainless steels are vulnerable to chloride cracking even at ambient temperatures [15, 18, 20]. Survey data suggests no safe level of chloride concentration below which cracking will not occur. However, the probability of failure in processed, pure water is low with chloride levels less than 1 ppm [18]. The NPRDS industry failure data does not support a problem with SCC of stainless steels in a raw water environment.

The use of low carbon and stabilized grades of austenitic stainless steels, or solution heat treatment at 1800^{o}F to 2100^{o}F can be effective in minimizing intergranular attack at welds. The use of low carbon grades such as type 304L has given superior performance in environments where other grades have exhibited knife-line attack [15].

SCC of Nickel-Base Alloys

In general, nickel-base alloys are more resistant to SCC in the presence of impurities and oxygenated water than are austenitic stainless steels. However, it is conservatively assumed that the threshold values of impurities reported above for austenitic stainless steels apply to nickel-base alloys--i.e., sulfates (>100 ppb), chlorides (> 150 ppb) and fluorides (>150 ppb) at ambient temperatures and above. In addition, nickel-base alloys are susceptible to SCC when exposed to high-purity deaerated water at elevated temperatures. Recent studies of Alloy 600 in a PWR environment [28] show that primary water stress-corrosion cracking (PWSCC) occurs when high tensile stress, high temperature, and a susceptible microstructure are simultaneously present. All failures of Alloy 600 components reported in the field resulted from high residual tensile stresses introduced during fabrication. Other factors that may possibly influence susceptibility include high lithium and high hydrogen content. In addition, Alloy 82 and Alloy 182 weld metals may be susceptible to PWSCC.

SCC of Copper Based Alloys

Some copper alloys are very susceptible to stress corrosion cracking in the raw water environments encountered in nuclear plants. The necessary ingredients for SCC in copper alloys, as for all metals, are sustained stress in conjunction with a specific degradation environment and/or chemical substance. Where chlorine is the common contaminant associated with SCC of stainless steel, chlorine does not promote SCC in copper alloys. The necessary chemical substance for SCC to occur in copper alloys is ammonia or other ammonium compounds. These chemical substances are oftentimes used in raw water systems to control the fluid pH or can be present as a result of an ammonium based cleaning solvent. Ammonia is also present in the atmosphere and raw water supplies as a by-product of organic decay. In addition to ammonia or ammonium compounds, oxygen and moisture are required to promote SCC in the copper alloys. Other contaminants such as carbon dioxide may increase the rate of cracking. In an atmosphere environment, a small moisture film on the metal surface is capable of absorbing a significant amount of ammonia, even from air containing a low ammonia concentration [13].

Copper alloys containing greater than 15% zinc are highly susceptible to stress-corrosion cracking. The best-known example of stress corrosion cracking is probably the “season cracking” of yellow brass ammunition shells in a moist ammonia environment [3, 5]. Brass alloys containing less than 15% zinc exhibit almost no susceptibility to SCC. Conversely, brasses containing 20 to 40% zinc demonstrate high susceptibility to SCC with susceptibility increasing as the zinc content is increased. Inhibited copper alloys produced by the addition of small amounts of other alloying elements (e.g. Sn, As, etc.) have demonstrated increased resistance to selective leaching, however, these inhibited alloys do not appear to provide an increased resistance to SCC [13]. All copper alloys, (both brasses and bronzes) containing in excess of 15% zinc should be considered susceptible to SCC regardless of any added inhibiting elements.

Bronze (copper-tin alloys), copper nickel and copper silicon alloys are considerably more resistant to stress corrosion cracking than the copper-zinc (brasses) alloys [3, 5]. These alloys are not considered susceptible to SCC/IGA for this raw water tool. Aluminum bronze, however, has exhibited high susceptibility to SCC in a moist ammonia environment [13].

Intergranular corrosion of copper alloys does not occur frequently, however, when it does occur it is usually associated with high-pressure steam environments. The effects of this degradation mechanism are similar to SCC except that mechanical stress is not required to initiate the intergranular corrosion [13]. Typically the alloys that are susceptible to SCC are also susceptible to intergranular corrosion. These include Muntz metal, admiralty metal, yellow brass, commercial bronze and aluminum brasses. One exception to the inclusion rule appears to be silicon bronze alloys which are resistant to SCC but do demonstrate a susceptibility to intergranular corrosion.[13]. Since raw water environments do not include high pressure steam, and the aging effects for IGA and SCC are similar, this tool logic does not differentiate between IGA and SCC.

SCC off Carbon And Low-Alloy Steels
The literature shows that SCC of carbon and low-alloy steels is possible in aqueous chlorides. One of the most reliable methods of preventing SCC of carbon and low-alloy steels in aqueous solutions is to select a material with a yield strength of less than 100 ksi [19]. The yield strength of carbon steels typically used in raw water systems are in the order of 30 to 45 ksi. Although one case of SCC of carbon steel has been reported, SCC of carbon steels in raw water applications is not an identified problem based on industry data and utility surveys. The one reported case is suspected to be nitrate induced SCC of carbon steel in a treated water system. For the purposes of this tool, SCC of carbon and low-alloy steels is not considered a plausible nuclear plant aging mechanism in raw water systems.

3.2.3 Fatigue

Cracking due to fatigue is discussed in Appendix H.

3.3 Reduction of Fracture Toughness

3.3.1 Thermal Aging

Thermal aging is a time and temperature dependent mechanism where microstructural changes lead to increased yield and tensile strength properties, decreased ductility, and degradation of toughness properties. Cast austenitic stainless steels [23] and precipitation-hardenable stainless steels [24] are known to be susceptible to thermal aging at temperatures of 600-650^{o}F and it has been projected that it can occur at temperatures as low as 550°F when exposures are long. The temperature range for embrittlement of these materials is typically between 700-1000°F [25]. Thermal aging of carbon steels and cast iron is not significant under the conditions of BWR or PWR operation [13,26]. Copper alloys in general demonstrate good fatigue resistance and at the raw water temperatures to which they are subjected, thermal aging is not a concern [13]. Since raw water temperatures are well below the threshold temperatures required to cause thermal aging and embrittlement, these aging mechanisms are not considered applicable to the materials within the scope of this mechanical tool.

3.3.2 Radiation Embrittlement

Radiation embrittlement can result in a decrease in fracture toughness of metals, however, the neutron exposure of components and systems using a raw water/carbon steel or stainless steel application is much less than the neutron fluence required to cause radiation embrittlement [2]. Therefore, radiation embrittlement is considered not applicable.

3.4 Distortion

Distortion may be caused by plastic deformation due to temperature-related phenomena (e.g., creep). In general, distortion is addressed by the design codes and is not considered an applicable aging effect. Creep is not a plausible aging mechanism since the high temperatures required for this mechanism to occur (generally at temperatures > 40% of the alloy melting point) are not observed in nuclear plant systems.

3.5 Summary of Potential Aging Effects

The aging effects evaluation discussed in previous sections is summarized in Table 3-1. These aging effects are categorized as: Loss of Material, Cracking, Reduction of Fracture Toughness, and Distortion. The aging effects evaluation shows that a loss of material is the only aging effect category applicable to carbon steel, low alloy steels and cast iron in a nuclear plant raw water environment. Loss of material includes general corrosion, crevice corrosion, pitting corrosion, MIC, corrosion in the presence of macroorganisms/silt, galvanic corrosion, erosion, erosion/corrosion and selective leaching. (Selective leaching is included in this category even though the aging effect is loss of material structural integrity versus wall thinning.) Loss of material strength and properties due to selective leaching is a concern for gray cast iron unless the material is coated or lined. Due to the aggressiveness of this environment many of these forms of corrosion can occur either individually or in combination with other mechanisms. .

Stainless steel and nickel-base alloys have two applicable aging effect categories in a raw water environment, loss of material and cracking. Although more resistant to general corrosion, these stainless steels and nickel-base alloys are more susceptible to localized pitting and crevice corrosion, particularly in a raw water environment. Additionally, the contaminates present in raw water make cracking due to SCC and IGA a potential aging concern.

Copper alloys exhibit similar types of aging effects (i.e. material loss and cracking) to stainless steels and nickel-base alloys. While resistant to general corrosion, pitting and crevice corrosion of copper alloys is a concern, although there are many copper alloys that demonstrate high resistance to these mechanisms. Several copper alloys are very susceptible to selective leaching of either zinc or aluminum. This effect occurs in brasses and bronzes with greater than 15% zinc content and in aluminum bronzes with greater than 8% aluminum content. Stress corrosion cracking and IGA of those same alloys is also a significant effect in a raw water environment.

There is a contrast in how corrosion aging effects are manifested on components. Programs that are credited with managing aging predominantly focus on these “effects” and not on the aging mechanisms themselves; so, it is important that the relationship between the aging mechanisms and the “effects” are identified. As an example, the loss of material resulting from general corrosion is uniform, whereas it is localized for the other corrosion mechanisms. This may be an important factor in determining the effectiveness of detection and management programs. For example, with uniform corrosion, the wall thinning can lead to gross failure (although the rate is very slow and usually predictable). With localized loss of material, the material loss is concentrated with relatively small material weight loss leading to a through-wall failure (although the rate can be very fast and unpredictable). Through-wall failures associated with localized corrosion are generally pin-hole type leaks which allows time for leak detection before impairing component or system function.

3.6 Operating History

An operational history review was performed using NPRDS and review of NRC generic communications that apply to raw water systems. Each is reported below.

3.6.1 NPRDS Review

One of the operating plant experience databases reviewed was the Nuclear Plant Reliability Data System (NPRDS). There are several concerns and/or precautions regarding the use of this data; however, the informative nature of the data outweighs the recognized limitations.

Table 3-1 Summary of Potential Aging Effects

Materials	*Loss of Material*	*Cracking*	*Reduction of Fracture Toughness*	*Distortion*
Carbon Steel Low Alloy Steel Cast iron	Applicable aging mechanisms include: • General Corrosion • Crevice Corrosion • Pitting Corrosion • MIC • Fouling • Galvanic Corrosion • Erosion/Erosion-Corrosion • Selective Leaching (gray cast iron only)	Not Applicable (See Appendix H for Fatigue)	Not Applicable	Not Applicable
Stainless Steel Nickel Alloys	Applicable aging mechanisms include: • Crevice Corrosion • Pitting Corrosion • MIC • Fouling • Erosion	Applicable aging mechanisms include: • Stress-Corrosion Cracking • Intergranular Attack (See Appendix H for Fatigue)	Not Applicable	Not Applicable
Copper Alloys	Applicable aging mechanisms include: • Crevice Corrosion • Pitting Corrosion • MIC • Fouling • Galvanic Corrosion • Erosion/Erosion-Corrosion • Selective Leaching (brass/bronze with >15% Zn; and Al. Bronze >8% Al)	Applicable aging mechanisms include: • Stress-Corrosion Cracking • Intergranular Attack (See Appendix H for Fatigue)	Not Applicable	Not Applicable

For the NPRDS database query, the following search conditions were selected:

- Selected Safety Classes are Safety-related Components, Nonsafety-related Components, and Other
- Selected Failure Cause Categories are Age/Normal Usage, Unknown, and Other
- Excluded Corrective Action is Recalibrate/Adjust
- Selected NSSSs are Babcock & Wilcox, Combustion Engineering, Westinghouse and General Electric
- Selected Systems are; Low Pressure Service Water-BW; Nuclear Service Water-CE; Nuclear Service Water-Westinghouse; Essential Service Water-GE; and Diesel Cooling Water-GE
- Selected Components are ACCUMU, FILTER, PIPE, PUMP, VALVE, and VESSEL
- Excluded PIPE Failure Mode is Plugged Pipe
- Excluded PUMP Failure Mode is Failed to Start
- Excluded VALVE Failure Modes are Failed to Close, Failed to Open, Internal Leakage, Fail to Operate Properly, Fail to Operate as Required, Premature Opening, and Fail to Remain Open

Selected Failure/Cause Descriptions are Foreign Material/Substance, Particulate Contamination, Normal Wear, Welding Process, Abnormal Stress, Abnormal Wear, Mechanical Damage, Aging/Cyclic Fatigue, Dirty, Corrosion, Binding/ Sticking, Mechanical Interference, Environmental Condition and Other.

There were 1392 records meeting the search condition(s) for PWR plants and 918 records meeting the search condition(s) for the BWR plants. These records were reviewed and those involving consumables such as failed/worn gaskets or packing materials were manually excluded. Also excluded were entries such as worn pump impellers, bearings, seat leakage, valve internals damage, and clogged filters. The remaining records numbered 251 for PWRs and 205 for BWRs, which were considered equipment aging issues applicable to the licensing renewal scope of components. The number of records and the percentage of total were tabulated in the following Tables 3-2 and 3-3. The NPRDS data and observations are reported separately for the PWRs and BWRs. The reason is that the searches were done at different times and not because significant differences in results were expected between PWR and BWR raw water systems.
The following items are observations from a review of the data.

1. There appears to be no conformity among the plants in reporting Service Water System data. For example, three sites were reporting 161 entries or 64% of the total number of failures.

2. The failure descriptions and cause descriptions often are too vague to evaluate.

3. The causes of many failures seem to be misdiagnosed. For example, attributing failures to normal wear when the failure description clearly points to pitting or some other form of corrosion often occurring over a short period of time. Several of the erosion entries, especially those occurring downstream of throttle valves, were probably due to cavitation. Many of the erosion and erosion-corrosion entries involved erosion or deterioration of a lining/coating which then exposed the base material to another form of corrosion mechanism such as pitting, crevice, or MIC.

4. Although Service Water Systems are normally considered to be primarily carbon steel systems, over 16% of the failure entries were either Type 304 or Type 316 stainless steels. This indicates that the systems or portions of systems were either originally designed using stainless steels or that a material substitution from carbon to stainless is occurring, or both. In any case, the data show that stainless steels are not immune to many corrosive effects.

5. All the potential effects identified by the Raw Water Tool appear in the NPRDS data with the exception of SCC of stainless steels. See the discussion in Section 3.2.2

6. Figure 1 depicts the number of failures by year. It shows an increasing trend beginning in the mid-80s, peaking at 48 failures in 1990, then rapidly decreasing to negligible failures between 1991 and 1995. The lack of data in the 70s is probably due to poor reporting practices before the NPRDS became the responsibility of INPO in 1981. The large increase in failures in the late 80s could have prompted the issue of Generic Letter 89-13 on Service Water System problems. It is also possible that the issue of GL 89-13 could have focused attention on the problems and promoted a more rigorous reporting practice. Assuming the reporting practices did not change significantly between the mid-80s and mid-90s, the data indicate that actions as required by GL 89-13 have had positive results.

Table 3-2 NPRDS Search Summary for PWRs

Failure Cause	No. of Entries	% of Total
Corrosion	130	52%
Erosion	16	6%
Erosion/Corrosion	19	7.5%
MIC	14	5.6%
Cavitation	11	4.4%
Pitting	6	2.4%
Vibration	2	0.8%
Weld Defect	3	1.2%
Galvanic	1	0.4%
Normal Wear	45	18%
Abnormal Wear	1	0.4%
Unknown	4	1.6%

Figure 1 PWR NPRDS Service Water System Failures

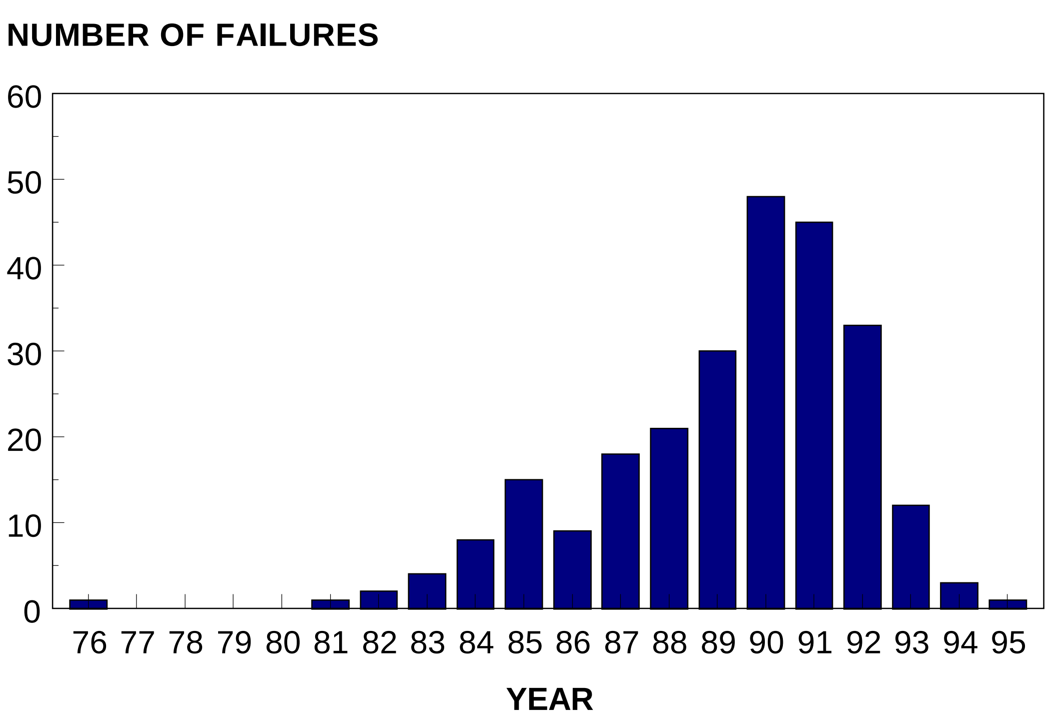
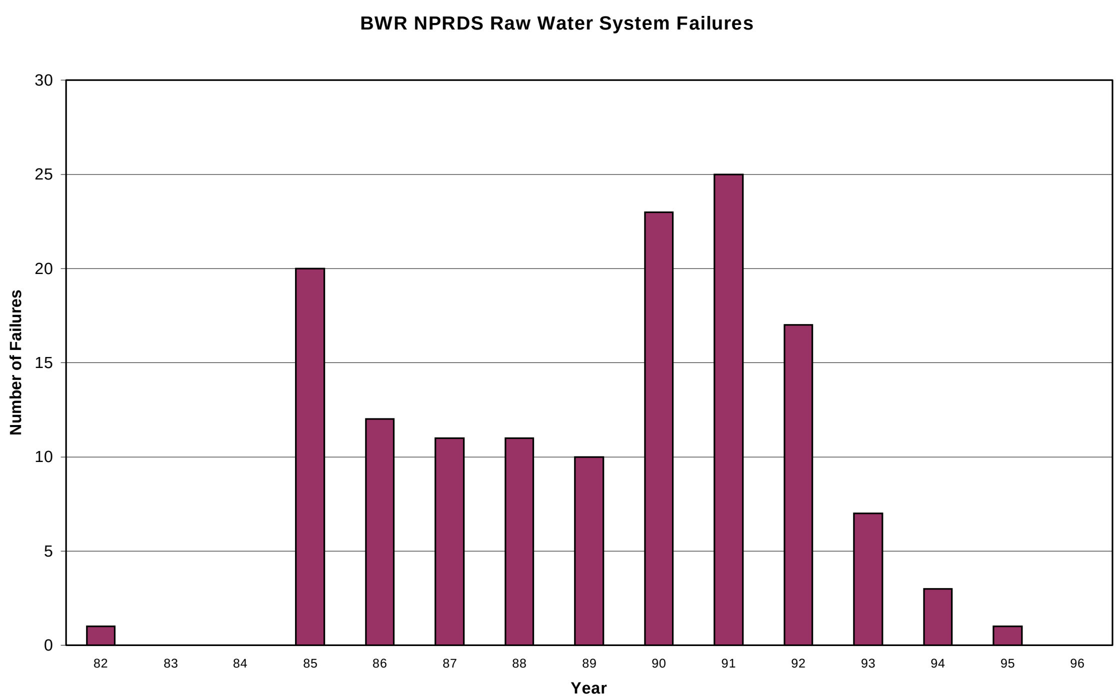


Table 3-3 NPRDS Search Summary for BWRs

Failure Cause	No. of Entries	% of Total
Corrosion	42	20.6%
Erosion-Corrosion	39	19.1%
Fittings, Threaded Conn., Nipples	22	10.8%
Pinhole Leaks	14	6.9%
Pitting	7	3.4%
Weld Cracking	8	3.9%
Galvanic Corrosion	3	1.5%
Cavitation	3	1.6%
MIC	2	1.0%
Bolting	3	1.5%
Waterhammer	1	0.5%
Normal Wear	60	29.6%

Figure 2 BWR NPRDS Raw Water System Failures



Observations

1. Fourteen of the 42 corrosion failures occurred in 1991 at one utility. The causes were attributed to saltwater corrosion of carbon steel piping as a result of removing the rubber lining during previous maintenance activities. No corrosion or erosion-corrosion failures have been reported for that utility since 1991.

2. No failures have been reported for corrosion or erosion-corrosion since 1993. The only failures reported after 1993 were two nipple cracks and one galvanic corrosion because of using a copper gasket.

3. Twenty of the 39 Erosion-Corrosion failures between 1985 and 1992 were at one utility involving seawater and carbon steel. Many of these failures were attributed to degradation of the interior protective coating. No failures have been reported since 1992. Remedial action was to apply two coats of ARCOR S-16 epoxy. Prior to 1992, Belzona coating was applied.

4. The BWR raw water systems had a total of 918 entries - 849 from the Essential Service Water and 69 from the Diesel Cooling Water.

5. The normal wear failure data (60 entries) was included to be consistent with the PWR data recorded. There was not enough information provided to determine the number of these failures which may be a result of aging mechanisms (e.g., replacement of valves and components with no other reason than aging and normal wear).

6. Prior to 1985, there was only one NPRDS failure reported by BWR raw water systems (one erosion-corrosion failure in 1982). Observation 6 for the PWR data is applicable to the BWR data. The trend by year for the BWR data, discounting normal wear failures, is shown in Figure 2 below.

7. As with the PWRs, there does not seem to be a conformity among the plants in reporting service water system data. For example, three sites were reporting over 46% of the total number of failures (excluding normal wear failures).

8. Two of the galvanic corrosion failures reported in 1993 and 1995 involved the use of copper gaskets. The other galvanic failure occurred in 1985 and involved a carbon steel and stainless steel coupling.

9. Both of the MIC failures were reported from the same site, one in 1989 and one in 1991. The material was carbon steel. It is possible that MIC failures are more widespread than reported in the NPRDS, and that some of the causes reported as pitting, pinhole leaks, and corrosion may be attributable to microorganisms. The difference between pitting and MIC is difficult to discern without a thorough investigation.

10. The three cavitation failures were associated with valve throttling. The remedial action was to replace the valve internals with an anti-cavitation trim.

11. The failures were weighted toward sea/brackish water versus fresh or river water by a ratio of approximately 65 to 35%.

3.6.2 NRC Generic Communications

A search was made of generic NRC correspondence that might relate to aging degradation in non-Class 1 mechanical and structural components. The documents searched were: Circulars, Bulletins, Information Notices, and Generic Letters. Of these, 22 were considered to be related, either directly or indirectly, to the raw water/carbon steel or stainless steel combinations. Seventeen were Information Notices, three were Generic Letters, and two were IE Bulletins. These entries are discussed briefly below.

Information Notices

IN 79-07: Rupture of Radwaste Tanks
In November, 1977 a radwaste tank ruptured at the Millstone Nuclear Power Station. Two problems led to the tank failure. First, the tank vent, which was intended to relieve excessive pressure in the radwaste tank, had been plugged by accumulated solidified boric acid concentrates. Second, corrosion had weakened the capability of the radwaste tank to withstand pressure. Individually, or in combination, these problems were causative factors in the rupture of the radwaste tank due to overpressurization. This tank had a history of corrosion problems such that the corrosion probably caused some weakness which contributed to the rupture. The tank was constructed of type 304 stainless steel. The plant was a seacoast site such that significant amounts of chlorides were present in the aerated waste system and, consequently, in the waste concentrate tank. The presence of significant amounts of chlorides, coupled with residual welding stresses in the type 304 stainless steel, resulted in chloride stress corrosion.

IN 80-37: Containment Cooler Leaks and Reactor Cavity Flooding at Indian Point Unit 2
Indian Point 2 experienced significant, multiple service water leakage from the containment fan cooling units. These units have a history of such leakage.

IN 81-21: Potential Loss Of Direct Access To Ultimate Heat Sink
An event at San Onofre Unit 1 and two events at the Brunswick Station have indicated that situations not explicitly discussed in Bulletin 81-03 may occur and result in a loss of direct access to the ultimate heat sink. These situations are: 1) Debris from shell fish other than Asiatic clams and mussels may cause flow blockage problems essentially identical to those described in the bulletin. 2) Flow blockage in heat exchangers can cause high pressure drops that, in turn, deform baffles, allowing bypass flow and reducing the pressure drop to near normal values. Once this occurs, heat exchanger flow blockage may not be detectable by pressure drop measurements. 3) Change in operating

conditions. (A lengthy outage with no flow through seawater systems appears to have permitted a buildup of mussels in systems where previous periodic inspections over more than a ten year period showed no appreciable problem.)

IN 83-46: Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem
This notice also warns about common-mode failures of other components or systems using brackish and/or silty service water. The concerns are plugging resulting from marine growth or silt deposit, leakage resulting from corrosion or erosion or a combination.

IN 84-71: Graphitic Corrosion of Cast Iron in Salt Water
Calvert Cliffs Unit 2 reported through-wall corrosion in the salt water side of their CCW system. They identified the corrosion as graphitic corrosion where an electrolytic cell is established between the graphite and the iron within the cast iron itself when in contact with water containing enough dissolved salts to act as an electrolyte. The phenomenon generally occurs on ships or coastal plants, but the Notice states that it can occur inland if the raw cooling water is sufficiently contaminated. The attack can be minimized by installation of "sacrificial" zinc plates. Other ways to reduce the attack are by choosing alternate materials or the application of a corrosion resistant coating. The Notice cautions that the coating approach must be carefully implemented because a small break in the coating concentrates the attack at the location and accelerates the local rate of corrosion. BG&E replaced the waterboxes and coated with a coaltar-epoxy. They also committed to developing a long-term program for monitoring the integrity of cast iron components in salt water service.

IN 85-24: Failures of Protective Coatings in Pipes and Heat Exchangers
Palo Verde Nuclear Generation Station Unit 1 personnel discovered delamination and peeling of the interior epoxy lining in three 24-inch 90 degree elbows in the spray pond piping and similar epoxy failures in the epoxy lined diesel generator heat exchangers. The epoxies were Plasite 7122-H and Plasite 7155-H. The failures were attributed to improper installation methods and inadequate curing times. Repairs were successfully made with Plasite 9009-IT and a final report was issued on the subject.

IN 85-30: Microbiologically Induced Corrosion of Containment Service Water System
H. B. Robinson reported significant corrosion pitting due to MIC in stainless steel piping of their service water system. Inspection revealed leakage at 54 weld joints. Numerous sleeve assemblies were required to restore integrity of the welds degraded by the corrosion attack. The Notice mentions several general methods for inhibiting MIC that have had varied degrees of success. Methods mentioned included application of protective coatings in conjunction with cathodic protection, corrosion inhibitors, or water chemical treatment such as periodic shock chlorination. The Notice also mentions that relatively rapid fluid flow tends to prevent attachment of organisms whereas low flow rates or stagnant conditions favor biofouling and concentration cell corrosion. Also, cleaning and dry lay up, or periodic recirculation flushing, during extended outages to mitigate known biological activity would appear to be prudent alternatives.

IN 85-56: Inadequate Environment Control for Components and Systems in Extended Storage or Lay-Up
Four cases were cited where instances of improper storage or lay-up has resulted in significant damage and extended plant outages. Two cases at Nine Mile Point Unit 2 and Hope Creek involved corrosion damage in heat exchangers due to standing water in the components in storage prior to operation. The incidents at H. B. Robinson reported in IN 85-30 above were reiterated. The fourth case was reported by Palo Verde where corrosion had been caused by contaminated water inadvertently left in the auxiliary feedwater pumps after prestartup flushing of the system.

IN 86-96: Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems
This Notice was to alert recipients to the potential for fouling in heat exchangers in raw water systems that may impair the heat removal capability assumed in the safety analysis. The Notice also referenced recommendations of NUREG/CR-4626 which included: (1) a thorough system evaluation to focus surveillance and control efforts for the best return on plant safety and efficient operation, (2) revision of plant technical specifications to reflect improved procedures, (3) monitoring the effectiveness of control procedures as a part of the surveillance program, and (4) including biofouling surveillance in the routine maintenance program.

IN 88-37: Flow Blockage of Cooling Water to Safety System Components
This Notice was issued to alert recipients to a potentially generic problem involving flow blockage in safety-related piping interconnections due to biofouling. The Notice describes an event at Catawba Unit 2 wherein the auxiliary feedwater flow became degraded after suction switchover from the condensate storage tank to the safety grade nuclear service water system. After disassembly, the flow control valves were found to be clogged with Asiatic clam shells. After the incident, Duke Power initiated a program of flushes and inspections of dead legs between the service water system and various safety-related systems.

IN 89-01: Valve Body Erosion
Inspections by the Brunswick Steam Electric Plant, Unit 1, indicated areas of significant but localized erosion on the internal surfaces of several carbon steel valve bodies. Identical valves in Unit 2 also indicated similar erosion. A similar problem at Hatch Unit 1 was attributed to cavitation in a 24-inch globe valve. The root cause for the Brunswick problem was not finalized at the time the Notice was released, but the licensee believed that the erosion was caused by cavitation by throttling the globe valve below its design range.

IN 89-76: Biofouling Agent: Zebra Mussel
This Notice was to alert addressees to potential problems related to biofouling of service water and cooling water systems that may result from a recently identified biofouling agent, Dreissena Polymorpha (zebra mussel). The zebra mussel is a small mollusk native

to the Black, Caspian, and Azov Seas that was discovered in Lake Erie of the Laurentian Great Lakes of North America in 1988. The mussel can potentially obstruct flow of water through pipes, hoses, screens, and condensers when their numbers are substantial. Biofouling attributed to this mussel was observed at several power plants. Areas of immediate concern were along the Great Lakes and major tributaries and canals.

IN 90-26: Inadequate Flow of Essential Service Water to Room Coolers and Heat Exchangers for Engineered Safety-Feature Systems
This Notice was to alert addressees to potential problems resulting from using the wrong flow and pressure drop relationship in establishing adequate flow of essential service water to room coolers for engineered safety-feature systems and from failing to establish or maintain balanced flows in essential service water systems. The notice pointed out that the relationship between flow and pressure drop for room coolers could vary even for the same vendor component because of design differences (with or without cleanout plugs). Measurements using flow instrumentation confirmed this.

IN 90-39: Recent Problems with Service Water Systems
This Notice cites eight instances of problems in service water systems which could cause failure of an adequate supply of cooling water to safety-related components. On March 9, 1990, Clinton reported flow distribution problems in the essential service water system. On March 14, 1990, Surry reported closed dampers which caused the diesel engine to fail to start. On March 21, 1990, Peach Bottom reported that emergency service water flow was inadequate due to silt and corrosion product accumulations. On March 23, 1990, River Bend reported MIC problems in the service water system. Acidic well water was used for the initial fill causing corrosion. The chemistry was corrected and the acidic attack stopped, but not the MIC. They plan to chemically clean or replace the piping as necessary. On March 26, 1990, Haddam Neck found that the service water flow to one of the emergency diesel generators was below that assumed in the safety analysis. On March 27, 1990, Farley reported inadequate service water flows to some safety loads without operator action. On April 3, 1990, Perry had to declare a service water pump and diesel generator inoperable due to a failed gasket. On April 11, 1990, Fitzpatrick reported that silt had been found in check valves in emergency service water lines to the seal coolers for two pumps in the RHR system.

IN 94-03: Deficiencies Identified During Service Water System Operational Performance Inspections
This Notice was to alert addressees to deficiencies identified by the NRC during service water system operational performance inspections that were performed. Deficiencies identified included inadequate evaluation of heat transfer requirements, inadequate testing programs and procedures, and weaknesses in the implementation of Generic Letter 89-13. Of particular note was the failure to include certain safety components and lines into the IST, inspection, or maintenance programs. This Notice does not specifically address aging mechanisms or effects; however since these programs are sometimes credited with managing effects, the findings illustrate the importance of systematic engineering analyses, testing, inspection, and maintenance of service water systems.

IN 94-59: Accelerated Dealloying of Cast Aluminum-Bronze Valves caused by Microbiologically Induced Corrosion

On October 12, 1993, Surry operators noted varying degrees of corrosion in 22 Jamesbury cast aluminum-bronze ball valves in 2-inch and less service water lines. This Notice is not directly applicable since the material is not carbon steel, however, it shows the presence of sulfate-reducing and acid-producing bacteria in service water systems. This Notice reports flows of 2 to 3 fps in the subject system and states flows less than approximately 5 fps lends to the system the potential for fouling which can promote MIC. Surry planned to replace the valves with valves more resistant to the conditions in the service water system.

IN 94-79: Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping

On February 12, 1994, a through-wall leak developed in the service water system supply piping to the emergency diesel generator. The licensee determined that the leak was caused by poor initial weld quality and MIC. On May 6, 1994, Beaver Valley found a through-wall leak on the river water system header to the emergency diesel generators. The leak was in the below grade portion of a 6-inch A106 Grade B carbon steel piping. The cause of the pitting and leak was determined to be MIC. Cultures contained sulfur-reducing bacteria and the anaerobic bacteria Clostridium. The Notice states that stagnant or intermittent-flow conditions, as in the case of emergency diesel service water supply headers, are conducive to the growth of microorganisms that can accelerate corrosion rates. It is noted that stainless steels are not immune to MIC and that MIC could damage metals lined with polymeric materials, typically at coating imperfections. Alternatives discussed were replacement materials, mechanical or chemical cleaning, water treatment, and continuous flow conditions. It was also noted that an existing program at Haddam Neck of hypochlorite injection was not successful in mitigating MIC problems in stagnant dead-end lines at such locations as the emergency diesel generator supply.

The significance of these Information Notices is summarized by the following points:

1. The raw water in service water systems provides an aggressively corrosive environment which is deleterious to most materials of construction.

2. Care should be taken in the application and curing of any protective coatings for corrosion protection to ensure effectiveness. Complete coverage is also required.

3. MIC is a recurring problem in many service water systems.

4. Improper lay-up during extended outages and stagnant or low flow conditions during pre-operational startup testing can cause significant corrosion problems for service water systems.

5. Valve body erosion is usually caused by cavitation as a result of operating or throttling outside the design basis for that valve.

6. Macrofouling has occurred in stagnant portions of piping and periodic flushing/inspection may be required to control the problem.

7. It is important to properly implement the requirements of Generic Letter 89-13.

The information in the Notices did not contradict any of the reasoning or logic used to develop the raw water/carbon steel or stainless steel tools.

IE Bulletins

BL 76-01: BWR Isolation Condenser Tube Failure
Condenser tube had a one-inch hole at the "U" bend. Eddy current testing showed that 30% of the remaining tubes had extensive cracking to a depth greater than allowed for minimum wall thickness.

IE BULLETIN 81-03: Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (asiatic clam) and Mytilus sp. (mussel)
In September of 1980, Arkansas Nuclear One, Unit 2, was shut down after discovering that tech spec requirements for minimum service water flow rate through the containment cooling units were not met. The inadequate flow was due to plugging by Asiatic clams. Clams were found in other equipment cooled by service water in both Units 1 and 2. Proper flow rates were restored only after the clam debris had been removed manually from the containment cooling units. The Bulletin discusses the original finding of Asiatic clams in 1938 and their spread across the United States and Tennessee Valley Authority experience. The Bulletin also discusses methods of control and their effectiveness including chlorination, heat, and mechanical cleaning. The Bulletin required the following actions to be taken by the Licensees:

1. Determine whether Corbicula sp. or Mytilus sp. is present in the vicinity of the station in either the source or receiving water body.

2. If it is unknown or confirmed that either species is present, determine whether fire protection or safety-related systems using the water are fouled by clams.

3. If clams, mussels or shells were found or their presence was not confirmed, measure flow rates through individual components in potentially affected systems to confirm adequate flow rates.

4. Describe methods either in use or planned for preventing and detecting future flow blockage or degradation due to clams or mussels or shell debris.

5. Describe the actions taken in items 1 through 3 and include the following information:
    a) Applicable portions of the environmental monitoring program.
    b) Components and systems affected.

c) Extent of fouling if any existed.
d) How and when fouling was discovered.
e) Corrective and preventive actions.

Generic Letters

GENERIC LETTER 91-13 - Essential Service Water System Failures at Multi-Unit Sites
Follow-up to GL 89-13. Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or plugged.

GENERIC LETTER 90-05 - Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping
This Generic Letter is included because most safety related service water systems are ASME Class 3 or equivalent and GL-90-05 provides the guidance that will be considered by the NRC staff in evaluating relief requests submitted by licensees for temporary non-code repairs. The guidance applies when flaws are discovered during power operation and relief is requested for a temporary repair until the next scheduled outage exceeding 30 days.

GENERIC LETTER 89-13 - Service Water System Problems Affecting Safety-Related Equipment
This Generic Letter was issued by the NRC, based on operating experience and studies, to require licensees to supply information regarding service water systems to assure the NRC that the system's safety functions and compliance with the General Design Criteria will be met.

Specific actions required under GL 89-13 include:

1. Implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling for open-cycle service water systems.

2. Conduct a test program to verify heat transfer capability of all safety-related heat exchangers controlled by the service water systems.

3. Establish a routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the safety-related functions.

4. Confirm that the service water system will perform its intended safety functions.

5. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure performance of safety functions and that operators will perform effectively.

4. FLOW DIAGRAM DEVELOPMENT

Figure 3 is the logic diagram to be used in raw water systems for stainless steel and nickel-base alloys. Figure 4 is the logic diagram to be used to find locations susceptible to aging in raw water systems for carbon steel, low alloy steel and cast iron. Figure 5 is the logic diagram to be used for copper alloys in a raw water environment. The following assumptions, general discussion, and respective tool descriptions apply to these logic tools.

4.1 Assumptions

1. Oxygen level is a significant parameter in many aging mechanisms. It is assumed that the oxygen level of all raw water is at or above the threshold for corrosive effects.

2. Halides, sulfates, and other aggressive contaminants, singly or in combination with oxygen, significantly influence the nature, rate, and severity of corrosion effects. The assumption is made that these impurities exist in all raw water at levels which will promote corrosive effects.

3. Crevice corrosion requires some type of crevice (an opening usually a few thousandths of an inch or less in width) to occur. It is unreasonable to expect an evaluator to respond to a question of whether or not a crevice exists within a system or component. The logic, therefore, will assume conservatively that the potential exists for crevices in all components and systems.

4. Pitting requires stagnant or slow moving fluid such that contaminants can concentrate on the metal surface. For the purposes of this tool logic, low flow for fresh water is defined as <3 ft/sec based on industry experience that shows velocities of 2 - 3 ft/sec keep the impurities from precipitating to the component surfaces and minimizes silting, biofouling, and MIC [4]. Low flow for sea water is defined as <5 ft/sec [3,16].

5. Some aging effects are the result of mechanisms that require the material to be under stresses which would be difficult to predict without detailed knowledge of all fabrication, maintenance and operating history. The level of stresses necessary to cause these aging effects are also dependent on material type, temperature and fluid environment. It would be unreasonable to determine for each application whether or not sufficient stresses exist to allow a particular aging mechanism to occur. This tool logic conservatively assumes that stresses sufficient to cause these aging effects are present.

6. Microorganisms of various types that influence corrosion either directly or indirectly are assumed to exist in some degree in all raw waters.

7. Fouling caused by various macroorganisms and silting can caused flow blockage and loss of heat transfer for all materials when exposed to raw water. Therefore, the raw water tools identify flow blockage as potential aging effects when there is a potential for macrofouling.

4.2 General

The mechanical tools being developed are intended to provide an efficient method to identify applicable aging effects for systems and components which are required to undergo an aging management review in compliance with the license renewal rule. Implementation of these tools at the various sites will result in the identification of plant equipment and aging effects which must be managed or justified not to be managed during the renewal period. Demonstration of the adequacy of aging management programs to manage these effects is outside the scope of this tool and will be addressed separately.

These tools will identify potential aging effects and also direct the user to areas in the system where these effects might be preferentially manifested. The age degradation discussion in the previous section identifies numerous aging mechanisms and their associated aging "effects" which potentially can occur in the raw water system equipment addressed by these tools. These logic tools, Figures 3, 4 and 5 then guide the user through logic to determine, based on specific system or component materials, environment and/or operating conditions, whether these effects are applicable. The tools described in the following sections address the "effects" of aging on stainless steel, nickel-base alloy, carbon steel, low alloy steel, cast iron, and copper alloy equipment which contains raw water. These tools are organized such that the individuals utilizing the tool do not require detailed knowledge of aging mechanisms or their effects. The logics do, however, require that the user be familiar with the materials of construction, various applicable environments, and all system operating conditions.

The evaluation logic groups various aging effects such as loss of material, cracking, etc., to quickly and efficiently disposition equipment. Implementation of the tool, in effect, documents the dispositioning of aging mechanisms, the resultant aging effects, and provides a link to the program evaluations and Aging Management Review (AMR) phase. The results not only identify the effects which must be managed but, given the screening criteria, can be a valuable input when determining how and where to implement aging management programs.

4.3 Tool Description

4.3.1 Stainless Steel and Nickel-Base Alloys

Figure 3 contains the logic and criteria to evaluate aging effects for the stainless steel and nickel-base alloy components within raw water systems.

The upper branch addresses the cracking and loss of material effects due to stress-corrosion cracking/intergranular attack and crevice/pitting corrosion, respectively. Raw water is assumed to contain high levels of oxygen and impurities. The existence of crevices and sensitized stainless steel are also assumed in the stainless steel logic. This upper branch discriminates between stagnant and low flow conditions as pitting corrosion is only a concern in these environments. SCC/IGA and crevice corrosion are a concern regardless of flow conditions.

The next branch addresses the potential for microbiological induced corrosion (MIC) in a raw water environment. Numerous methods exist to control MIC (biocide addition, cathodic protection) and this logic allows includes consideration of these methods under the stipulation that programs to monitor their effectiveness are in place.

Although erosion-corrosion is not an applicable aging effect for stainless steel, erosion due to particulate matter can occur depending on the nature and amount of suspended particulate matter in the flowing fluid and the fluid velocity. The third branch identifies erosion as a potential aging effect in locations where such particulate matter can result in a loss of material due to erosion.

The last branch addresses the potential for material loss due to macroorganisms and/or silting. These contaminants typically exist only on equipment directly connected to raw water sources such as rivers, oceans, etc. This aging effect is only a concern where the potential for such contamination exists. Where the potential exists, various methods are used to control such contamination and the logic includes consideration for these methods.

4.3.2 Carbon Steel, Low Alloy Steel and Cast Iron

Figure 4 contains the logic and criteria to evaluate aging effects for the carbon steel, low alloy steel and cast iron components within raw water systems.

The upper branch addresses the loss of material properties and subsequent loss of component structural integrity due to selective leaching (also called graphitization) of gray cast iron. Coatings or liners with adequate integrity verification are effective in preventing this mechanism and the logic includes such consideration.

The next branch of Figure 4 addresses the loss of material effects due to general corrosion, crevice corrosion, and pitting corrosion. Many raw water components are either lined or coated to prevent contact of the fluid with the metal. Provisions are included in the logic to eliminate corrosion effects from further consideration as long as programs are in place to assure the continued integrity of the linings or coatings. Since the assumption has been made that high oxygen and high impurities exist, the operative condition to promote pitting corrosion is low or stagnant flow. The flow rate does not significantly impact the susceptibility to general corrosion or crevice corrosion. (Under low flow conditions a protective surface film limits general corrosion. Low flow can exist in crevices even under high bulk fluid flows, with subsequent crevice corrosion possible under these conditions.)

The third branch assumes microorganisms are present in raw water systems and, if the pH is less than 10 and if there are no programs to control microorganisms, then material loss due to MIC is a concern. Cathodic protection and/or liners/coatings are also credited with eliminating MIC.

The fourth branch asks whether there is the potential for macrofouling/silting and whether there is a program to effectively address the problem if it exists or has the potential to exist.

The fifth branch checks for locations or geometries with high velocities which may increase the potential for erosion or erosion-corrosion.

The last branch checks for the potential for galvanic corrosion where dissimilar materials are in contact. A metal is susceptible to galvanic corrosion when electrolytically connected to a material higher in the galvanic series. The potential for galvanic corrosion is higher in service water systems because of the high incidence of material change-outs and interfaces with other systems or components which are stainless steels. Cathodic protection or the use of sacrificial anodes (with adequate monitoring and inspection) minimizes the aging effects from this aging mechanism.

4.3.3 Copper Alloys

Figure 5 contains the logic and criteria to evaluate aging effects for the copper alloy components within raw water systems.

The upper branch checks for the possibility of galvanic corrosion at any location where there is electrolytical contact between dissimilar materials. The potential for galvanic corrosion is higher in service water systems because of the high incidence of material replacement and interfaces with other systems or components which are stainless steels. Cathodic protection or the use of sacrificial anodes (with adequate monitoring and inspection) minimizes the aging effects from this aging mechanism.

The second branch addresses the loss of material properties and subsequent loss of component structural integrity of brasses and bronzes with > 15 % zinc content and aluminum bronze with > 8% aluminum due to selective leaching. The addition of an inhibiting element during manufacture of a susceptible alloy prevents selective leaching. (Naval brass, for example, is produced by the addition of an inhibiting element to Muntz metal.)

The third branch addresses the loss of material due to pitting corrosion and crevice corrosion in. Stagnant or low flowing conditions are a prerequisite for pitting/crevice corrosion and only affects the identified copper alloys (within the scope of alloys covered by this tool).

The fourth branch addresses stress corrosion cracking of aluminum bronze and some brass/bronze alloys with > 15% zinc content. The presence of ammonia or ammonium is a necessary ingredient to stress corrosion cracking of these alloys.

The fifth branch checks for locations or geometries with high velocities which may increase the potential for erosion or erosion-corrosion.

The sixth branch assumes microorganisms are present in raw water systems and, if the pH is less than 10 and if there are no programs to control microorganisms, then material loss due to MIC is a concern.

The last branch addresses the potential for damage as a result of macroorganisms and/or silting. If the potential does exist, the logic includes consideration of effective programs to control these contaminants.

Figure 3 Raw Water/Stainless Steel Tool

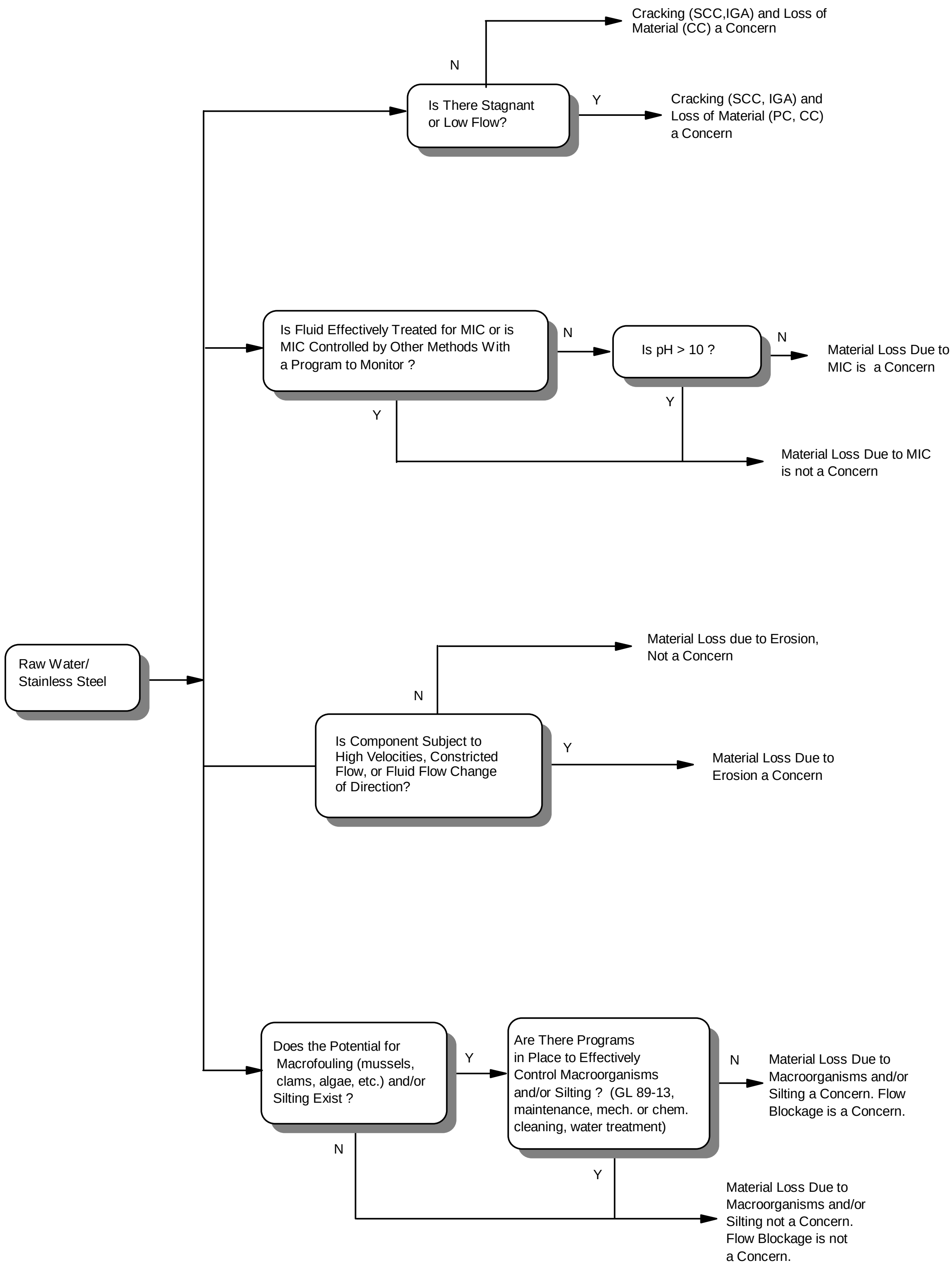


Figure 4 Raw Water/Carbon Steel Tool

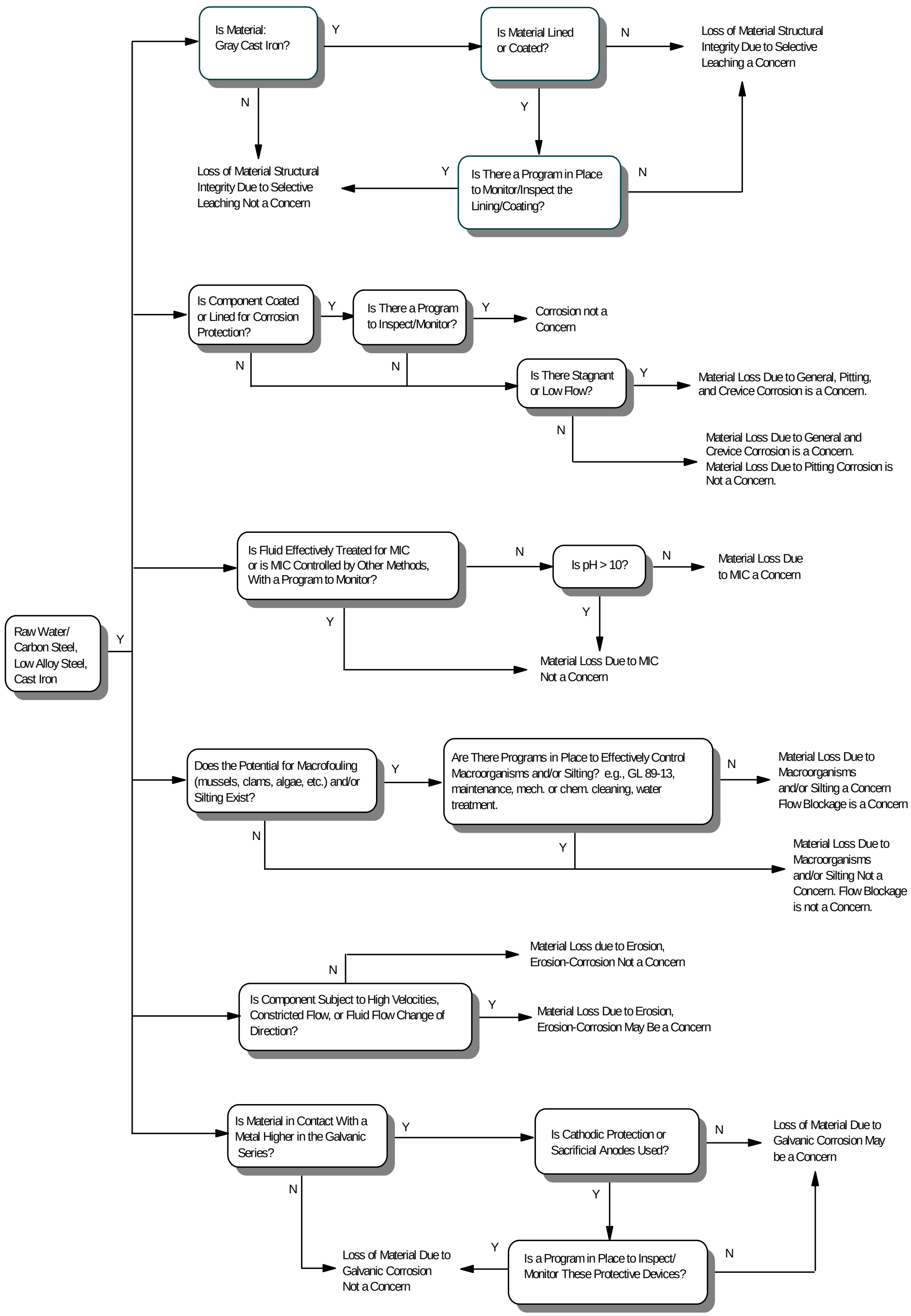
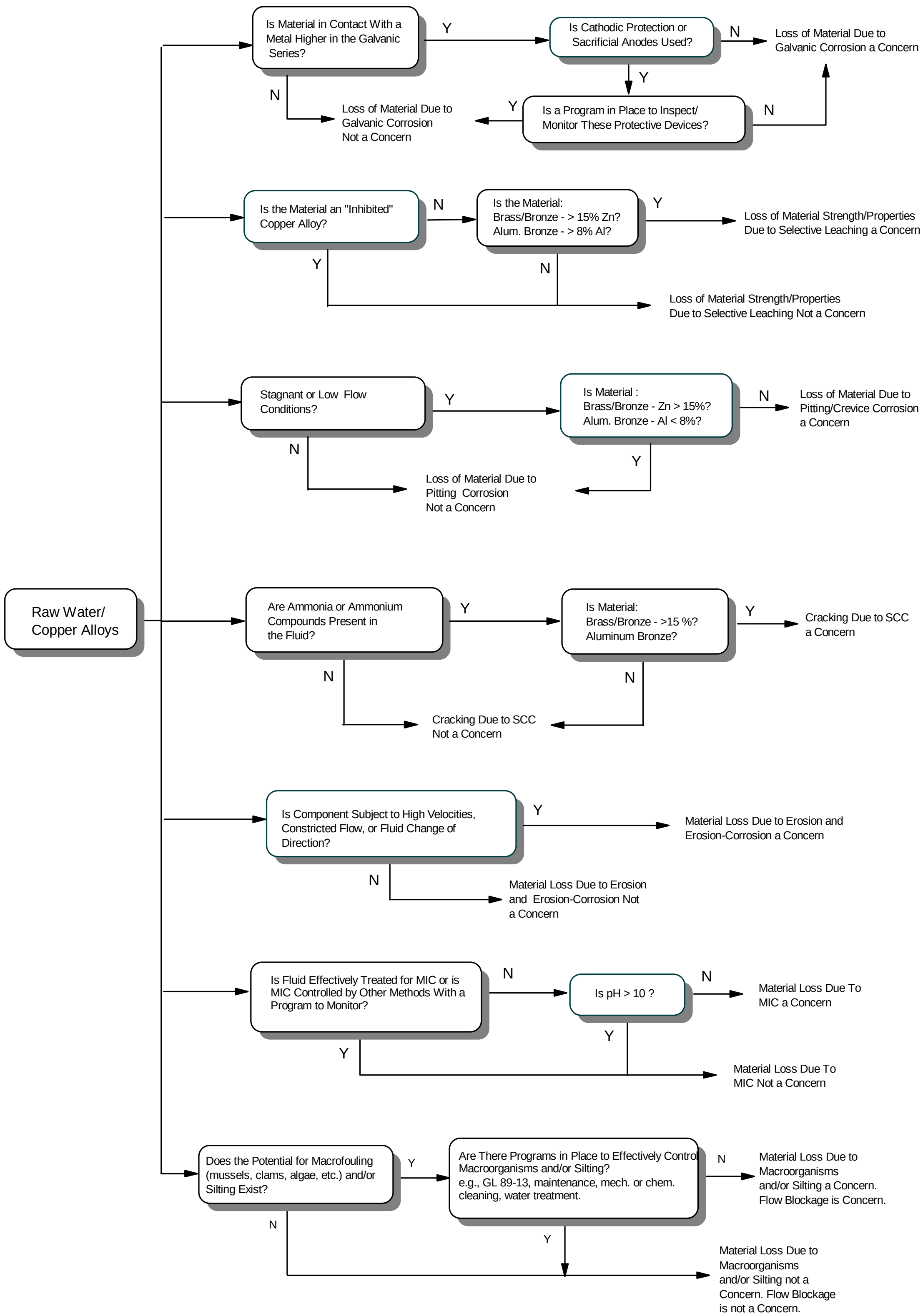


Figure 5 Raw Water/Copper Alloys



5. CERTIFICATION

This appendix is an accurate description of aging effects of carbon steel, low alloy steel, cast iron, stainless steel, nickel-base alloys and copper alloys in a raw water environment prepared for the B&W Owners Group Generic License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date

Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date

GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

D J Firth 8/14/99

David J. Firth Date

GLRP Project Manager

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Appendix C - Lubricating Oil and Fuel Oil

The Lubrication Oil and Fuel Oil Tool provides a methodology for identifying the aging effects in portions of systems and components that may be subjected to an internal environment of either lubricating oil or diesel fuel oil. This tool is designed for use in evaluating any component with a lube oil or fuel oil internal environment which includes, but is not limited to, portions of emergency diesel lube oil and fuel oil systems, safe shutdown diesel lube oil and fuel oil systems, fire protection system oil and lube oil systems, etc. This tool can also be used to evaluate other plant equipment components whose internal environment is lubricating oil such as high/low pressure spray or injection pumps, decay heat/residual heat removal pumps, etc. The materials covered in this tool are stainless steels, carbon and low-alloy steels, aluminum, cast iron, and various copper alloys (brass, bronze, and copper-nickel).

Lubricating oil systems generally do not suffer appreciable degradation by cracking or loss of material since the environment is not conducive to corrosion mechanisms. There are some conditions, however, in which moisture intrusion into the systems can result in an aggressive environment. The oil tool logic assumes that degradation effects are insignificant for oil systems without moisture intrusion.

Fuel oil can be a much more corrosive environment if there should be an intrusion of water during transportation and storage. MIC is also a potential concern in fuel oil systems. The fuel oil logic acknowledges the necessity for water contamination before most aging effects can occur and the logic allows individual plants to credit inspection and sampling programs if they can be shown to be effective in controlling the environment sufficiently to prevent moisture intrusion.

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1. INTRODUCTION

This aging management tool is intended to cover systems and components containing lubricating oil and/or fuel oil. This tool provides a consistent approach to determining various aging mechanisms and their effects which could prevent the accomplishment of license renewal "intended" functions. Although intended to address those systems and components within the scope of license renewal, the method and approach used makes it acceptable to use this tool wherever the equipment or component internal fluid is oil or fuel oil. While it is acceptable to use on systems and equipment outside the scope of license renewal, this tool incorporates NPRDS equipment failure history and NRC generic correspondence data only for the systems and equipment within the scope of license renewal.

Oil has a variety of applications at power plants, most notably as a lubricant for major rotating equipment. Equipment containing lube oil that is within the scope of license renewal includes emergency and essential diesel generator systems; high/low pressure spray and injection pumps; decay heat/residual heat removal pumps; emergency feedwater pumps; essential raw and treated water system pump; air compressors; and various fire system pumps and diesel generators.

Diesel fuel oil is used as a fuel to power diesel engines that drive generators and diesel driven pumps. This tool is directly applicable to the majority of components necessary to supply fuel oil to the emergency and essential equipment diesel generators, including the fuel oil storage tanks and supply lines.

In addition to the lube oil and fuel oil systems, fire protection regulations for Pressurized Water Reactor (PWR) plants require an oil collection system for the reactor coolant pump (RCP) lube oil systems. The purpose of this collection system is to provide for draining and storing of any RCP lube oil leakage to reduce the likelihood of a containment fire resulting from that leakage. This tool can also be applied to the reactor coolant pump and applicable oil collection systems.

The materials used in parts of the above described components and systems typically include a number of alloys. Carbon steel and stainless steel are typically used for piping, tanks, pressure vessels, and heat exchangers. (Heat exchangers are covered separately in Appendix G). Oil and fuel oil system piping and fittings are fabricated from carbon steel, stainless steel, copper alloys (brass, bronze, and copper-nickel), aluminum, and cast iron. Nonmetallic materials used for gaskets, packing, O-rings, and seals are excluded from aging management, as described in Section 2.2 of the Implementation Guideline.

2. MATERIALS AND ENVIRONMENTS

The oil and fuel oil tool is intended to assist the evaluator in determining locations within oil and fuel oil systems that may be susceptible to one or more of the following aging effects: cracking, loss of material, and reduction in fracture toughness. This tool evaluates the pressure boundary components of the various lube oil and fuel oil systems, which include tanks, piping, pump casings, valve bodies, instruments, and fittings. Although heat exchangers are specifically addressed in Appendix G, this tool can be used to complement the heat exchanger tool for certain portions of heat exchangers where the materials and internal environment reflect those covered by this tool.

The materials addressed in this tool are discussed in Section 2.1 and the various environments are described in Section 2.2.

2.1 Materials

A majority of the piping and components in systems containing oil or fuel oil are constructed of carbon steel. Lube oil systems consist of various pumps, piping, branch connections, and fittings, and typically include lube oil coolers. Fuel systems include storage tanks, piping, valves, and pumps. Appendix G is intended to specifically cover heat exchangers, including lube oil coolers. For completeness, this tool includes the more common tubing materials used in coolers, which include stainless steel, aluminum, and various copper alloys. The underground tanks in the diesel generator fuel supply systems are either carbon steel or stainless steel. The carbon steel tanks may be lined to prevent corrosion of the tank internal surface. This tool includes the evaluation of both lined and unlined tanks. The external surfaces are addressed in Appendix E.

The Reactor Coolant Pump (RCP) oil collection systems on PWRs are typically constructed of carbon steel with carbon steel collection tanks. Normally exposed to containment atmosphere, the oil collection systems may frequently collect other liquids and impurities.

The materials addressed in this tool include (1) wrought and cast stainless steels, including weld metals, (2) carbon steels and low-alloy steels, (3) aluminum, (4) cast iron, and (5) copper alloys (brass, bronze and copper-nickel).

2.1.1 Stainless Steels

The stainless steels covered in the oil and fuel oil tool are divided into the following categories: (1) wrought stainless steels, (2) cast stainless steels, and (3) weld metals. Each is discussed below.

Wrought Stainless Steels

Wrought stainless steels are commonly divided into five groups: (1) austenitic, (2) ferritic, (3) martensitic, (4) precipitation hardening, and (5) duplex stainless steels. Definitions of these groups of stainless steels are provided in Reference [1] and are not repeated here. Martensitic and precipitation hardening stainless steels are typically used for bolting, valve stems, and pump shafts, and are not evaluated in this tool. [Note: valve stems and pump shafts are not subject to aging management review in accordance with the discussion in Section 2.0 of this Implementation Guideline.] Bolted closures are addressed in Appendix F.

Cast Stainless Steels

The cast stainless steels addressed in this oil and fuel oil tool all contain ferrite in an austenitic matrix (i.e., CF series) and are commonly known as cast austenitic stainless steel (CASS). Typical alloys used in nuclear applications include CF-8 and CF-8M which are the cast counterparts of wrought Types 304 and 316, respectively. Other castings include CF-3 and CF-3M, which are the cast counterparts of Types 304L and 316L, respectively. Alloys CF-3M and CF-8M are modifications of CF-3 and CF-8 containing 2% to 3% molybdenum and a slightly higher nickel content to enhance resistance to corrosion and pitting.

Stainless Steel Weld Metal

The welding materials used to join stainless steels depend upon the type of material being joined. For example, Type 304 wrought austenitic stainless steels may be joined using either gas metal-arc welding (GMAW), submerged-arc welding (SAW), or shielded metal-arc welding (SMAW) processes with a Type 308 electrode or welding rod. The various welding processes used to join wrought stainless steels include SMAW, SAW, GMAW, Gas Tungsten-Arc Welding (GTAW), and plasma-arc welding (PAW). Flux core arc welding (FCAW) may have been used but to a lesser extent. Stainless steel welding processes typically used include SMAW, GTAW, GMAW, and electroslag [2].

The weld metal is assumed to be equivalent to the wrought austenitic stainless steels with respect to loss of material and resistance to cracking (initiation), as discussed in Section 3.0. However, it should be noted that strength and toughness of selected stainless steel weld metals used to join wrought stainless steels were shown to vary depending upon the welding process [4]. For example, flux welds, such as SAW and SMAW, were shown to provide joint properties with higher strength and significantly lower toughness than the surrounding base metal. Higher strength of the weld metal results in enhanced load bearing capacity compared to base metal; lower toughness of the weld metal may result in a reduced ability to support structural loads if a crack develops in the weld metal. The strength and toughness of non-flux welds, such as GMAW and GTAW, were shown to be similar to the base metal.

2.1.2 Carbon Steel and Low Alloy Steel

Carbon steel is used throughout nuclear plants in various applications. It is used where high corrosion resistance is not required and is the material of choice for pumps, valves, tanks, and fittings in most plant oil and fuel oil systems. The term carbon steel as used in the aging evaluation applies to all carbon and low-alloy steels.

2.1.3 Aluminum

Aluminum has limited use in nuclear plant applications. Due to its high resistance to corrosion in many environments, it is found in various oil and fuel oil system applications. Typical applications of aluminum in oil or fuel oil systems include instruments and heat exchangers.

2.1.4 Cast Iron

The term cast iron identifies a large family of ferrous alloys. Cast iron typically contains more than 2% carbon and from 1 to 3% silicon. The four basic types of cast iron are (1) white iron, (2) gray iron, (3) ductile iron, and (4) malleable iron. White cast irons have high compressive strength and good retention of strength and hardness at elevated temperature; they are most often used for their excellent resistance to wear and abrasion. Gray cast iron has several unique properties because of flake graphite in the microstructure. Gray iron can be machined easily at hardnesses conducive to good wear resistance. It has outstanding properties for applications involving vibrational damping or moderate thermal shock. Ductile cast iron is similar to gray iron in composition, but during casting of ductile iron, magnesium and cerium is added to the molten iron, which nodularizes the graphite giving the final product higher strength and ductility. Malleable iron has similar properties to ductile iron, however, it is more expensive to manufacture and is only used for thin section castings, and for parts requiring maximum machinability or where a high modulus of elasticity is required.

This oil and fuel oil tool evaluates only the more widely used white and gray cast iron alloys. Although comprising two general categories, various alloying elements can and are added to cast iron alloys to promote an array of hardness, corrosion resistance, heat resistance, and abrasion resistance properties [3].

2.1.5 Copper Alloys (brass, bronze, and copper-nickel)

Bronze and brass are copper alloys using predominantly copper, tin, and zinc with various other alloying agents present in differing amounts. Brass is an alloy composed of copper and zinc, with other metals in varying lesser amounts. Bronze is any of various alloys composed of copper and tin, sometimes with traces of other metals. Other copper alloys are used in various applications most notably copper-nickel alloys in condenser and heat exchanger tubing material.

Brass and bronze products are available in both cast and wrought product forms with most alloy compositions available in both. Brasses and bronzes containing tin, lead and/or zinc have only moderate tensile and yield strengths and high elongation. Aluminum bronzes, manganese bronzes, and silicon brasses/bronzes are used where higher strength alloys are required. Various brass and bronze alloys are used in a number of applications at nuclear plants. Due to their corrosion resistance, copper alloys are used to some extent in oil and fuel oil applications and are covered in this tool.

2.1.6 Coatings and Linings

Lining or coating of plant components (e.g., fuel oil storage tanks and piping) has proven effective in providing resistance to corrosion. There are several forms of organic, inorganic and metallic coatings and/or linings that are available with varying degrees of protection, permeability, and lifetime. The durability of a coating/lining is directly related to the preparation of the surface [12] and in some cases localized separation of the coating from the component ("holidays") will occur. Without cathodic protection or corrosion inhibition, all of the galvanic forces will be focused on the holiday, causing rapid corrosion of the material [12]. With either cathodic protection or additives to protect against corrosion, the effects of corrosive mechanisms on lined/coated material are minimized [12]. Because of the various types and associated life expectancies, it is essential that linings/coatings and cathodic protection have appropriate inspections and/or adjustments to fully credit these design attributes.

While all coatings/liners can exhibit localized failure as a result of surface preparation, finish, original application, physical damage, etc., Epoxy Phenolic coatings used on the lower portion of some fuel oil storage tanks have exhibited a high failure rate. Periodic inspection of Epoxy Phenolic coatings is warranted as a result of the extensive peeling and flaking observed with these coating.

2.2 Environment

This oil and fuel oil tool includes consideration of various hydrocarbon-based environments, specifically, the fuel oil and lubricating oil systems and components. These mechanical tools are intended to provide guidance in the identification of aging effects for these systems and components that support passive functions. This tool is not intended to cover portions of equipment such as bearings and rotating pieces associated with purely active functions. (As outlined in the Implementation Guideline, the mechanical tools are intended to cover only those system and component functions that are passive.)

A major portion of the components and environments considered by this tool are associated with the diesel generators or other emergency power generators, diesel fuel systems and lubricating oil systems. The environments considered by this tool also are intended to cover the various component pressure boundaries of other plant rotating machinery that is exposed to lubricating oil. These other environments include the lubricating oil portions of large pumps (e.g., decay/residual heat removal; high/low pressure injection and spray; essential raw/treated water; emergency feedwater; etc.) that are within the scope of license renewal. Some of these pumps, diesel generators, and compressors use forced lube oil systems, which include oil coolers, pump housings, oil piping, and valve bodies. Other pumps without forced oil lubrication systems may only have an oil housing and oil cooler that are pressure boundary components requiring aging management review.

The reactor coolant pump lube oil collection system on PWRs is normally subjected to the containment atmosphere. This pump oil can at times leak, and the oil collection system will be exposed to this leaking oil environment. Because of the location of the oil collection system and the various designs at the different plants, the oil collection systems can be subjected to very different environments including condensation, oil leakage, and ambient containment environment. No single tool is capable of evaluating all these different environments and a combination of tools may be necessary depending on the plant specific equipment design and the applicable environments.

This appendix identifies aging effects associated with the various material and environmental combinations and it is not within the scope of this tool to outline the level of detail to which plants evaluate components. Most plants will probably not require aging management review for the oil reservoirs in motor operated valves, for example, as these components perform only active functions. The degree to which plants evaluate the lube oil systems for rotating equipment will be plant-specific. Some plants may elect to evaluate this equipment on a "skid-mounted" basis where the entire component is evaluated as one piece of equipment and aging management is assured using performance based programs. Other plants may elect to evaluate oil systems using this tool as a means to identify all appropriate aging effects. Most plants have specific programs to evaluate, test, and monitor lubricating oil to assure that the oil remains free of water and other contaminants. Under these conditions, the lube oil systems and components have few if any significant aging effects.

2.2.1 Fuel Oils

Diesel fuel oil is delivered to plants in tanker trucks and is stored in large tanks to provide an on-site available supply of diesel fuel for a specified period of diesel generator operation, typically 7 days). Fuel oil is supplied to the generators through pumps, valves, and piping. Strainers/filters and other equipment assure that the diesel fuel supplied to the generators is clean and free of contaminants. Different additives may be in the diesel fuel dependent on the different grades and refiners of the product. In addition, utilities may add fuel additives such as biocides and corrosion inhibitors to the fuel.

Water and other contaminants, such as chlorides and sulfides, occur naturally in crude oil. While fuel oil in its purest refined form contains little if any moisture, water contamination can occur during storage and transportation. This water contamination, naturally occurring contaminants, and any fuel additives, can produce an environment which is corrosive [9]. Chlorides and sulfides are especially damaging contaminants.

Several forms of fungus and other microorganisms can survive and multiply in hydrocarbon fuels. These organisms can occur in all areas of the fuel handling system and need only trace amounts of minerals and water to sustain their growth [12]. Their growth chemically alters the fuel by producing sludge, acids, and other by-products of metabolism. There are numerous methods to control fungi and microorganisms. The addition of biocides together with regular cleaning of the tanks is one such method.

2.2.2 Lubricating Oils

Metals are not corroded by the hydrocarbon components of lubricants, although corrosion does occur under certain conditions as the result of the presence of impurities or additives in lubricants and as a result of the development of oil oxidation products [6]. Lubricating oils are not good electrolytes and the oil film on the wetted surfaces of components tends to minimize the potential for corrosion [6,9]. Moisture contamination and the use of additives can, however, cause corrosion. Copper and copper alloys, for example, may be attacked by oxidized oil and active sulfur compounds [6].

The purity of the diesel generator lubricating oil systems is maintained at most plants and the fluid is chemically analyzed periodically. Where periodic testing and monitoring of lubrication oil in other equipment is performed, contamination would also likely be detected. Contamination of the oil in normally operating equipment such as makeup and service/raw water pumps may be introduced while performing equipment active functions subsequent to bearing failure, excessive vibration, or other causes. For equipment not normally in operation during full power operation (e.g. DHR/RHR pumps, High/Low Pressure Spray pumps, etc.) periodic testing of the equipment, in conjunction with an oil sampling program, should be able to detect any water contamination of the oil.

3. AGING EFFECTS

This oil and fuel oil tool addresses aging effects that result from aging mechanisms described in various Aging Management Guidelines, technical references and other industry sources. Where specific mechanisms are not applicable under the environmental and material conditions covered by this tool, justification is provided for a "not applicable" determination. For those effects that are applicable, a detailed discussion of the environmental conditions necessary for the effects to be manifested is included. Aging effects discussed below include loss of material, cracking, reduction of fracture toughness, distortion, and loss of mechanical closure integrity. When performing a system evaluation, if one or more of the aging mechanisms is plausible, then the aging effect is assumed to be applicable for the period of extended operation.

Each of the various aging mechanisms is discussed below for the environments and for the materials listed in Section 2.1 and 2.2. For the most part, aging effects are not observed in fuel oil and lubricating oil systems unless moisture or other contaminants are present.

3.1 Loss of Material

Loss of material (i.e., corrosion) is defined as the deterioration of a material because of electrochemical reaction with its environment. Lubricating oils and fuel oils in their pure form are non-aggressive and non-corrosive for all metals [13]. For the most part, the corrosion mechanisms discussed below require water contamination to provide an environment conducive to their initiation and progression. Some of the mechanisms also require that other contaminants (e.g., chlorides or sulfides) are present to support that particular mechanism. Unless specifically controlled or monitored, it is likely that additives to lubricating oils and fuel will contain sufficient levels of aggressive species such that, in the presence of water, corrosion will occur. Stagnant conditions are also necessary for many corrosion mechanisms.

3.1.1 General Corrosion

General corrosion is the result of a chemical or electrochemical reaction between a material and an aggressive environment. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup [8]. At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are necessary for the corrosion of iron and carbon steel; in this environment, carbon and low-alloy steels and cast iron are susceptible to general corrosion while stainless steels and aluminum are resistant to general corrosion [8].

Copper alloys (brass, bronze and copper nickel) may be attacked not only by oxidized oil, but also by the active sulfur compounds, which may be present [6]. However, most modern, well refined lubricants give little trouble with copper and in pure form will not corrode copper alloys. Although lubricants may tend to corrode materials under some conditions, they afford considerable protection against corrosion caused by the presence of moisture, and, where necessary, a high degree of antirust protection is achieved by the use of additives [6].

In summary, very little general corrosion occurs in oil and fuel oil systems because the oxygen content is very low and oil/fuel is not a good electrolyte. To assist in corrosion prevention, purification systems are usually installed and/or corrosion inhibitors are added to maintain these fluids free of corrosion products [7]. However, where water and other contamination are present and the water and contamination settles in stagnant areas such as tanks and the bottom of heat exchangers, general corrosion of carbon steel and low-alloy steels and cast iron can be a significant aging concern.

3.1.2 Galvanic Corrosion

Galvanic corrosion occurs when materials with different electrochemical potentials are in contact in the presence of an electrolyte [6]. The rate of galvanic corrosion is governed by the relative sizes of the anode and the cathode. The material with the lower potential (higher or galvanic series) is the anode and it sacrifices to the cathode. If the anode is appreciably larger than the cathode, then the galvanic corrosion rate is slow. Conversely, if the anode is much smaller than cathode, then the galvanic corrosion rate can be very fast in the presence of moisture and water.

The effects of galvanic corrosion can be precluded by design (e.g., isolation to prevent electrolytic connection or using galvanically similar materials). Carbon and low-alloy steels have lower potentials than stainless steels and would be preferentially attacked in a galvanic couple. Generally, stainless steels are not susceptible to galvanic corrosion [7]. Particular attention should be paid to component replacements and to carbon or low-alloy steel system interfaces with stainless steel.

Lubricating oils and fuel oil, even in the contaminated condition, are not good conducting electrolytes [9]. Some situations may exist, however, in which water and/or contamination may enter the oil or fuel oil systems. Under stagnant conditions, these contaminants may settle and separate due to the different fluid densities. Under such conditions, the water and any other contaminants will be in contact with the component material and a good conducting electrolyte can exist. This is most likely to occur in oil or fuel oil storage tanks rather than in the flowing portions of systems.

3.1.3 Crevice Corrosion

Crevices concentrate contaminants above levels of the bulk fluid environment, leading to accelerated corrosion known as crevice corrosion. Crevice corrosion can affect all metals and occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads [7]. Crevice corrosion is strongly dependent on the presence of dissolved oxygen and an aggressive environment. Oxygen is required for crevice corrosion initiation; however, once initiated, oxygen is not required to continue the corrosion process [11]. In addition to oxygen, crevice corrosion requires an aggressive chemical species (e.g., halides or sulfates) and moisture to provide an environment severe enough to promote crevice corrosion.

As discussed in the general corrosion section above, oil and fuel oil are not good electrolytes unless water and other contaminants are present. In flowing systems, even if contaminated, water and contaminants cannot accumulate in crevices to a significant extent and crevice corrosion is not expected to be a significant aging concern under flowing conditions. Crevice corrosion is, therefore, only a concern under stagnant conditions and where water contamination is present. If the conditions exist, none of the materials considered here are immune to crevice corrosion.

3.1.4 Pitting Corrosion

Pitting is localized attack that is very destructive because it causes equipment to fail with only a small percent weight loss of the entire structure. Pitting corrosion rates are very unpredictable. Failures are due to intense corrosion, which sometimes occurs with extreme suddenness [7]. Pits typically exhibit a long incubation period before they are made evident. In some instances pitting corrosion can initially occur at a high rate, but then display a very low corrosion rate as corrosion product buildup depletes the oxygen supply in the pit. Pit growth is also unique because it can be autocatalytic or self-stimulating and self-propagating once started [9].

Pitting corrosion is an aggressive corrosion mechanism that is more common with passive materials such as austenitic stainless steels than with non-passive materials which include carbon/alloy steels and cast iron. All materials of interest are susceptible to pitting corrosion under certain conditions. Most pitting is associated with halide ions; chlorides, bromides, and hypochlorites being prevalent [7].

Oil and fuel oil are not good electrolytes and water and aggressive species are necessary to propagate this corrosion mechanism. Pitting is a concern with all the metals considered in this report.

3.1.5 Erosion and Erosion Corrosion

Erosion is the loss of material due to a flowing fluid. Erosion-corrosion is a mechanism where fluid flow erodes or dissolves away the protective oxide or passive film of the metal, causing corrosion and re-oxidation. Impingement and solid particle erosion is caused by the impact of particles or liquid on a material. Elbows or T-type joints where the fluid flow changes direction are particularly susceptible to erosion [7].

This mechanism is not applicable to oil or fuel oil systems. The low flow rates and low contaminant levels in these systems do not support erosion-corrosion or particulate flow erosion.

3.1.6 Microbiologically Influenced Corrosion (MIC)

Microbiologically influenced corrosion (MIC) is corrosive attack caused by microbiological activity and usually occurs at temperatures between 50 and 120^{o}F; however, it can occur at temperatures up to 212^{o}F. Microbiological organisms disrupt the metal's protective oxide layer, produce corrosive substances, and deposit solids that accelerate the electrolytic reactions of corrosive attack, generally in the form of pitting or crevice corrosion. The bacteria of concern can be either aerobic or anaerobic. MIC is facilitated by stagnant conditions, fouling, internal crevices, contact with untreated water from a natural source, and contact with contaminated soils. MIC damage to the exterior of components (owing to contact with contaminated soils) is covered in Appendix E.

Several forms of fungus and other microorganisms can survive and multiply in hydrocarbon fuels [12]. This growth may occur in all areas of the system: storage tanks, pump trucks, delivery lines, and fuel tanks. When the fuel oil or lubricating oil is agitated, as would occur during tank filling, growth may be distributed throughout the system. These microorganisms use fuel oil as their main food source and only require trace amounts of minerals and water to sustain their growth. The by-products of their metabolism produce a corrosive environment, which can lead to corrosion.

While MIC contamination is possible in lubricating oil applications, the likelihood of MIC causing extensive damage in lube oil systems is minimal. Even if contamination of the oil occurs, the relatively clean systems and addition of corrosion inhibitors to the lubrication oil does not provide an environment conducive to microorganism growth. The potential for MIC growth and subsequent corrosion effects in lube oil systems appears to be very small based on the addition of lube oil corrosion additives, oil purity testing programs and the extremely low likelihood of lube oil contamination. Even if MIC were to be introduced into these systems, the sampling programs are likely to detect and correct the situation prior to MIC causing any appreciable corrosion of lube oil system components.

MIC has been found in fuel oil systems and, if left untreated, can cause extensive damage to piping and components. MIC can affect nearly all PWR materials of interest however, nickel-base alloys seem to be more resistant [14,15]. MIC is a concern for fuel oil systems and components due to the potential for microorganism introduction and moisture contamination during bulk fuel oil supply and delivery. The addition of a biocide at the fuel oil source and the fuel oil system, when properly monitored and controlled, eliminates the microorganisms necessary to induce this type of corrosion.

3.1.7 Wear and Fretting

Wear can result from the movement of a material in relation to another material. This can occur during a component's performance of active functions, which are not addressed by this tool (e.g., air compressor, pump, or valve operations). Wear can also occur as a result of movement on the external surfaces of equipment. External component wear is covered in Appendix E.

Fretting is caused by small amplitude vibratory motion [e.g., flow induced vibration (FIV)] which results in removal of material between two contacting surfaces [7]. With the exception of heat exchangers, passive components in systems containing oil and fuel oil are not susceptible to this mechanism. Heat exchangers are discussed in Appendix G.

General wear and fretting are, therefore, not applicable to the equipment covered by this oil and fuel oil tool.

3.1.8 Selective Leaching

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Common yellow brass (30% zinc and 70% copper) is most susceptible to this mechanism. Lower zinc levels and the addition of 1% tin, for example, significantly reduce the susceptibility of the material [7]. There are two general types of dezincification, uniform attack and localized plug attack. In both types of dezincification, the zinc ions stay in solution, while the copper plates back on. The dissolved zinc can then corrode slowly by the cathodic reduction of water into hydrogen gas and hydroxide ions [7]. For this reason, dezincification can proceed in the absence of oxygen. The rate of corrosion, however, is increased in the presence of oxygen. This process occurs in clean water with no additional contaminant required for initiation [7].

Gray cast iron can also display the effects of selective leaching particularly in relatively mild environments. This process initiates with selective leaching of the iron or steel matrix leaving the graphitic network. The graphite is cathodic to iron; providing an excellent galvanic cell. The iron is dissolved, leaving a porous mass consisting of graphite, voids, and rust. If the cast iron is in an environment that corrodes this metal rapidly (e.g., saltwater) uniform corrosion can occur with a rapid loss of material strength which can be undetected, since the corrosion appears superficial [7].

Aluminum bronze can be subject to de-alloying similar to the dezincification of brass. Aluminum brasses are used where impingement attack in turbulent high velocity saline water is the fluid. These alloys form a tough corrosion resistant protective coating due to the buildup of aluminum oxide. Proper quench and temper treatments for some of the aluminum bronzes produces a tempered structure that is superior in corrosion resistance to the normal annealed structures. Unless they are inhibited by adding 0.02 to 0.10% As, aluminum brasses are susceptible to selective leaching.

Oil and fuel oil are not good electrolytes [9]. As discussed in the above sections, the intrusion of moisture into these systems is required for selective leaching to be a concern.

3.2 Cracking

Service induced cracking (initiation and growth) of base metal or weld metal may result from one or more of the following aging mechanisms: hydrogen damage, stress corrosion cracking, vibration, and fatigue.

3.2.1 Hydrogen Damage

Hydrogen damage results from absorption of hydrogen into the metal. It includes the following degradation mechanisms:

- decarburization
- hydrogen attack
- hydrogen blistering
- hydrogen embrittlement

Decarburization, or the removal of carbon from steel, is produced by moist hydrogen at high temperatures. Decarburization is extremely slow below 1,000^{o}C [6], which is significantly above the temperatures seen by nuclear plant oil and fuel oil components.

Hydrogen attack refers to the interaction between hydrogen and a component of an alloy at high temperatures. Examples include the disintegration of oxygen-containing copper in the presence of hydrogen and methane-induced fissuring of steels [7]. Hydrogen attack occurs at temperatures above those experienced at nuclear plants.

Hydrogen blistering occurs as a result of the diffusion of monatomic hydrogen into voids in a metal. The atomic hydrogen then combines to form molecular hydrogen, which is unable to diffuse through the metal. The concentration and pressure of hydrogen gas in the void then increases with a resultant blistering of material. This mechanism is most prevalent in the petroleum industry where chemical reactions during the refining process produce significant levels of atomic hydrogen [7]. Hydrogen blistering can also occur where cathodic protection of tanks or other components is used, but only if the voltage is incorrectly set. Carbon and low-alloy steels are susceptible while stainless steels are much less susceptible. The industry experience search identified no incidences of hydrogen blistering in nuclear plant systems or equipment.

Hydrogen embrittlement is the degradation of material mechanical properties a result of absorption of atomic hydrogen into the material. As with hydrogen blistering, embrittlement requires the presence of monatomic hydrogen produced by a chemical process. High strength steels are the most susceptible to hydrogen embrittlement with the greatest susceptibility occurring around 70^{o}F. The susceptibility decreases rapidly as the temperature varies above and below 70^{o}F [6, 8]. Alloying with nickel or molybdenum reduces susceptibility [6,8], therefore, the stainless and nickel base alloys are considered immune to hydrogen embrittlement. The nuclear industry experience search did not identify any incidence of hydrogen embrittlement in oil or fuel oil applications.

In summary, potential hydrogen damage in oil and fuel oil systems can consist of hydrogen blistering and hydrogen embrittlement. Both occur primarily in the petrochemical industry during the refining process. With the exception of fuel oil storage tanks, it is not expected that equipment within the scope of this tool will experience the corrosive environment necessary for hydrogen damage. Fuel oil storage tanks are particularly susceptible to hydrogen damage if cathodic protection is used with an incorrect voltage setting.

3.2.2 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material. Intergranular attack (IGA) is similar to stress corrosion cracking except that stress is not necessary for it to proceed. Piping carbon steels are considered resistant to SCC when the yield strength is less than 100 ksi [15]. Since the yield strength of most piping used is in the 30 - 45 ksi range, SCC is not considered applicable to piping carbon steels.

The detailed evaluation and identification of operational and residual stresses are beyond the scope of this tool. It is assumed that the materials within the scope of this tool contain sufficient stresses to initiate stress corrosion cracking given an environment conducive to the progression of either SCC or IGA.

Stainless Steel (Wrought and Cast)

SCC and IGA have occurred in stainless steel typically in water systems containing dissolved oxygen, sulfates, fluorides or chlorides. Although temperatures above 200^{o}F are typically required, SCC has been observed at lower temperatures [6]. The presence of oxidizers often has a pronounced effect on cracking tendencies. In fact, the presence of dissolved oxygen or other oxidizing species is critical to the cracking in all chloride solutions. If the oxygen is removed, cracking will only occur if chloride concentration is very high. [6].

Aluminum

Pure aluminum is not susceptible to SCC/IGA, however, aluminum alloys are very susceptible to cracking under mild corrosive environments [7]. Aluminum alloys containing more than 12% zinc or more than 6% magnesium are susceptible to SCC/IGA in air and water vapor environments as well as in corrosive environments containing chloride solutions and/or salt water.

Copper Alloys

The best-known example of stress corrosion cracking is probably the “season cracking” of brass. One cause of the cracking is the presence of ammonia or nitrogen bearing materials in conjunction with moisture and oxygen. Carbon dioxide is also thought to contribute to the process [6,7]. Alloys containing 65% copper are extremely susceptible to SCC, with resistance to cracking increasing progressively as the content of copper increases [6]. Brasses, including admiralty metal, are susceptible to SCC if the zinc content is greater than 15%.

Bronze (copper-tin alloys) and other copper alloys are considerably more resistant to stress corrosion cracking than the copper-zinc (brasses) alloys [6]. Bronzes are not considered susceptible to SCC/IGA for this oil and fuel oil tool.

In summary, although the oil and fuel oil covered by this tool may contain additives which are conducive to causing stress corrosion cracking in many materials, the corrosion inhibitors, emulsifying agents and overall coating properties of lubricating oil are not likely to result in the conditions necessary for SCC in oil systems. In addition, the industry search identified no incidences of stress corrosion cracking in these systems. However, the environment in fuel oil systems is generally not as clean or corrosion resistant as in lubricating oil systems, especially in equipment likely to contain water contamination and stagnant conditions (storage tanks and heat exchangers are examples of locations in which external contaminants may accumulate). Therefore, SCC may occur in stainless steel and certain aluminum and copper alloys in fuel oil systems.

3.2.3 Vibration

Oil and fuel oil lines are typically small diameter piping and tubing which may be extremely sensitive to failures as a result of cracking due to vibration. These failures can occur where piping and/or tubing is in close proximity to such equipment as diesel generators or pumps in the fuel oil and lube oil systems.. All components are susceptible to this type of failure and it can occur regardless of temperature and environment. A majority of vibration failures occur as a result of high cycle fatigue. Especially where small bore piping and tubing is utilized, installed supports and restraints may not be adequate for the operating equipment. Because of the low operating time of some of the this equipment, not all vibration failures will have manifested themselves during the original licensing period.

This mechanical tool, based on significant industry failure experience, includes the logic to address vibration induced pressure boundary degradation. Some plants have had high incidences of vibration induced failures, while other plants have had relatively few such failures. The incidence of future failures will depend on whether or not such failures are just repaired, or a root cause program is initiated. Many plants have taken the approach that vibration failures are “infantile” in nature and are the result of design/installation/maintenance practices and are not an effect of aging. In many instances, these failures may be attributed, at least in part, to extremely high vibrations caused by equipment malfunctions such as pump bearing failures, and coupling failures. Plant specific failure history must be evaluated when addressing vibration failures. This tool logic accounts for this varied susceptibility to vibration induced failures and provides optional coverage to address this issue.

3.2.4 Mechanical/Thermal Fatigue

Aging effects due to mechanical/thermal fatigue are covered separately in Appendix H.

3.3 Reduction of Fracture Toughness

The fracture toughness of wrought austenitic stainless steel and cast austenitic stainless steel is typically higher than carbon and low-alloy steels. Aging mechanisms that may lead to reduction of fracture toughness include thermal embrittlement, radiation embrittlement, and hydrogen embrittlement. Hydrogen embrittlement is covered in Section 3.2.1 of this tool, which discusses hydrogen damage. The susceptibility of the materials listed in Section 2.1 to reduction of fracture toughness is discussed below.

3.3.1 Thermal Aging

Thermal aging, sometimes referred to as thermal embrittlement, is a time and temperature dependent mechanism where microstructural changes lead to increased yield and tensile strength, decreased ductility, and degradation of toughness. Cast austenitic stainless steels and precipitation-hardenable stainless steels are the only materials currently known to be susceptible to thermal aging for PWR conditions. Embrittlement of CASS is a concern for license renewal at temperatures of 482°F or more. The materials covered by this tool do not exceed 200^{o}F, therefore, thermal aging is not a concern for Lubricating Oil and Fuel Oil systems.

3.3.2 Radiation Embrittlement

Radiation embrittlement can result in a decrease in fracture toughness of metals, however, it requires neutron fluence values far exceeding 10^{17} n/cm^2. The components and systems covered by this tool are sufficiently far away from the reactor vessel where fluence values are significantly lower than 10^{17} n/cm^2 [8]. Therefore, radiation embrittlement is considered not applicable.

3.4 Distortion

Distortion may be caused by plastic deformation as a result of creep. In general, distortion is addressed by the design codes and is not considered an applicable aging effect. Creep is not a plausible aging mechanism since the high temperatures required for this mechanism to occur (generally at temperatures > 40% of the alloy melting point) are not observed in either PWR or BWR systems [8].

3.5 Loss of Mechanical Closure Integrity

The loss of closure integrity is addressed in Appendix F which covers bolted closures.

3.5.1 Stress Relaxation

Stress relaxation is a potential age related degradation mechanism (ARDM) for bolts in PWRs [3]. Since bolted connections are addressed in Appendix F, stress relaxation is not considered within this tool.

Table 3-1 Summary of Potential Aging Effects				
Materials	***Loss of Material***	***Cracking***	***Reduction of Fracture Toughness***	***Distortion***
Stainless Steels	Pitting Crevice Corrosion MIC	SCC See App. H for Fatigue	Not Applicable	Not Applicable
Carbon Steel	General Corrosion Pitting Crevice Corrosion Galvanic Corrosion MIC	Hydrogen Damage See App. H for Fatigue	Not Applicable	Not Applicable
Cast Iron	General Corrosion Pitting Crevice Corrosion Galvanic Corrosion MIC Selective Leaching	Hydrogen Damage See App. H for Fatigue	Not Applicable	Not Applicable
Copper Alloys	Pitting Crevice Corrosion Galvanic Corrosion MIC	SCC (> 15% zinc) See App. H for Fatigue	Not Applicable	Not Applicable
Brass	Pitting Crevice Corrosion MIC Selective Leaching	See App. H for Fatigue	Not Applicable	Not Applicable
Aluminum	Pitting Crevice Corrosion Galvanic Corrosion MIC	See App. H for Fatigue	Not Applicable	Not Applicable
Aluminum Alloys	Pitting Crevice Corrosion Galvanic Corrosion MIC	SCC (>12% zinc or > 6% Magnesium) See App. H for Fatigue	Not Applicable	Not Applicable

3.6 Summary of Potential Aging Effects

Table 3-1 contains a summary of the various aging mechanisms and effects considered during the development of this tool. Also included are the necessary conditions for these aging effects and the materials that are susceptible to these effects.

3.7 Operating History

An operational history review was performed using NPRDS and a review of NRC generic communications that apply to oil and fuel oil systems. Each is reported below.

3.7.1 NPRDS Review

The Nuclear Plant Reliability Data System (NPRDS) contains information on plant operating experiences. The purpose of a review of this material is to assure that failures of in-scope equipment due to aging is considered and also to assure that overly conservative assessments of equipment aging are not made.

The oil and fuel oil tool covers numerous systems and materials. As a result, it would be extremely time consuming to sort and review all NPRDS entries that cover this entire spectrum of failures. The search criteria included only diesel oil and diesel fuel system entries including the High Pressure Core Spray (HPCS) fuel oil and lube oil systems found in later BWR plants. There are several concerns and/or precautions regarding the use of this data. The materials identified and the failure causes are oftentimes incomplete or missing data and some interpretation is required. In areas involving pressure boundary degradation in close proximity to vibrating equipment, the probable root cause of vibration may not be identified. However, the informative nature of the data outweighs these recognized limitations.

For the NPRDS data base query, the following search conditions were selected:

- Selected Safety Classes are Safety-related Components, Non Safety-related Components, and Other

- Selected Failure Cause Categories are Age/Normal Usage, Unknown (included Code X prior to 4/94), and Other (was included in Code K prior to 4/94)

- Excluded Corrective Action is Recalibrate/Adjust

- Selected NSSSs are Babcock & Wilcox, Combustion Engineering, Westinghouse PWRs, and General Electric BWRs

- Selected Components are ACCUMU, FILTER, PIPE, PUMP, VALVE, and VESSEL

- Excluded PIPE Failure Mode is Plugged Pipe

- Excluded PUMP Failure Mode is Failed to Start

- Excluded VALVE Failure Modes are Failed to Close, Failed to Open, Internal Leakage, Fail to Operate Properly (Backfit Only), Fail to Operate at Required, Premature Opening, and Fail to Remain Open

- Selected Failure/Cause Descriptions are Foreign Material/Substance (include AJ before 4/94), Particulate Contamination, Normal Wear (included AH before 4/94), Welding Process, Abnormal Stress (Mech) (included AQ before 4/94), Abnormal Wear (included in AD before 4/94), Loose Parts (included AP before 4/94), Mechanical Damage (included BK before 4/94), Aging/Cyclic Fatigue (Mech) (included BL before 4/94), Dirty, Corrosion, Mech Binding/Sticking (included in BB before 4/94), Mechanical Interference (include in BF before 4/94), Environmental Condition (code added 4/94), and Other (code added 4/94)

- Selected Systems are Diesel Fuel Oil-BW, Diesel Lube Oil-BW, Diesel Fuel Oil-CE, Diesel Lube Oil-CE, Diesel Fuel Oil-W, Diesel Lube Oil-W, Diesel Fuel Oil-GE, Diesel Lube Oil-GE, HPCS Fuel Oil-GE, and HPCS Lube Oil-GE

The purpose of the NPRDS search was to identify equipment failures resulting from the effects of aging. Using the above search criteria, 478 entries were selected. These records were reviewed and those involving consumables such as failed/worn gaskets, packing material failures, and other diaphragm, seal or sealant failures were excluded from further consideration. Other failures relating to design problems, failures resulting from faulty maintenance, clogged filters and other various failures not related to equipment aging were also excluded.

Most of the selected entries were excluded. Of the 348 items identified, 283 involved failures of gasket, seal, sealant, diaphragm, “O” ring and other consumable items. The next largest category of failures involved “active” components.

The failure of a component to perform its active functions accounted for 117 entries. This category consisted of pump and valve failures associated with their active functions. Also included in this category were instances of isolation and relief valve internal leakage and failure to perform an active relief or isolation function. These types of failures impact the component “active” functions and are covered adequately by Maintenance Rule programs. These types of failures are, therefore, not addressed by these Mechanical Tools.

An additional 24 entries resulted from the failure of filters to perform their required functions. This included both clogged and partially blocked filters and strainers. High differential pressures were cited as the cause of many filter/screen failures. In all cases the filter and/or strainer was cleaned or replaced and the system returned to operable status.

Electrical failures accounted for 9 entries. These failures included electrical equipment and instruments such as pump motors, coils, thermostats, and bearing temperature elements.

There were only 45 entries that represented equipment failures resulting from the effects of aging. Table 3-2 identifies the number of records attributed to the various aging mechanisms and includes a percentage of the total for each category.

Table 3-2 NPRDS Search Summary

Failure Cause	No. of Entries	% of Total
Leaking hoses/fittings/tubing	22	49
Cracking	9	20
Threaded Connections	7	15
Loose bolts/plugs	7	15

Most of the failures attributed to aging did not specifically identify the cause of failure. In the PWR data search, the failures of hoses, fittings and tubing, for the most part, were simply listed as leakage of the various components with no cause identified. It is likely that at least some of the other failures were also attributable to vibration. Many of the failures occurred in equipment either directly connected to pumps (fittings/hoses/tubing attached to pumps) or in the vicinity of the vibrating equipment (location identified as pump discharge relief valve, pump downstream fitting, pump inlet connection.) . The BWR search, however, did attribute a number of failures specifically to vibration. Additional failures in the BWR data may also be attributable to vibration for the same reasons as indicated above for the PWR data.

Cracking of welded joints accounted for nine failures. Most of the cracked welded joints involved fittings such as nipples, couplings, and flanges. One failure of a check valve body attributed to cracking was included in this grouping. As discussed above for the hose/fittings/tubing failures, some of these cracking failures may be the result of vibration, however, that conclusion cannot be determined from the data.

There were seven failures of threaded attachments. Some were directly attributed to vibration; however, for a majority of the cases, it was not clear whether the failures were due to corrosion of the threads, wear due to repeated maintenance of the component, or vibrational wear. Some failures may simply be a result of aging of the thread sealant, which is considered to be a consumable.

Seven failures were classified as loose bolts or plugs. In most cases, the cause of these failures was not apparent from the available NPRDS data.

3.7.1.1 Summary of NPRDS Search

The NPRDS review verifies that corrosion or cracking failures of lubricating oil components are infrequent. This review also reflects the extremely low incidence of failure of components exposed to lubricating oil and fuel oil; the search did not identify any incidents of corrosion in these systems. Of the nine incidences of cracking, none could be directly attributed to corrosion or other pressure boundary material loss aging effects, although no specific causes were identified. It is likely that a number are attributable to vibration.

Although not specifically identified as vibration caused failures, the NPRDS data does suggest that a significant number of failures in the vicinity of rotating equipment were caused by vibration. Several failures of fittings, hoses, flanges, worn threaded connections and loose bolts specifically identified vibration as the suspected cause of failure. Some of the failures of gaskets and sealant, although included in a category for consumable items and not considered an aging concern, also could be considered the result of vibration. In some instances, failures were co-incident with high vibration resulting from pump and/or coupling failures.

3.7.1.2 Observations and Limitations in Using the NPRDS Search Results

The following observations and limitations were noted during the review of the NPRDS entries.

1. The exact cause of failure is often not clear because of to the vagueness of the information.

2. Because of the relatively low cost of replacement of items in the oil/fuel oil systems, the cause of failure is often not evaluated and the items are replaced with the same part with identical or similar design and materials.

3. Many pressure boundary failures as a result of aging of consumables such as O-rings, gaskets, sealant, and diaphragms, were described. Unlike the failure of these types of components in other systems (e.g., air systems), the failures in the diesel lube oil and diesel fuel systems resulted, in many instances, in the loss of system functions.

4. Because of the high safety significance of diesel generators and the fire hazard resulting from oil or fuel spills, most of these failures resulted in degraded system status even though many of the pressure boundary failures may not have been sufficiently severe to affect the system functions.

5. The screening criteria included only emergency diesel lube and fuel oil systems even though there are numerous other system and components that contain lube oil (e.g. DHR/RHR pumps, high and low pressure injection and spray pumps, service/raw

water pumps.). The amount of time necessary to review all potential lube oil component failures required that the scope of the search be limited.

3.7.2 Applicable NRC Generic Correspondence

A search was made of generic NRC correspondence that might relate to aging degradation in oil and fuel mechanical boundary components. Oil and fuel oil systems include the diesel generator fuel and various hydraulic and lube oil systems servicing plant components including main feedwater and auxiliary feedwater. The NRC generic communications include Circulars, Bulletins, Information Notices, and Generic Letters. Eight entries were found to be related, either directly or indirectly, to the oil or fuel oil system components. The entries are summarized below.

Circulars

CR 80-11: Emergency Diesel Generator Lube Oil Cooler Failures

Diesel generator lube oil cooler failures were reported. The DGs were manufactured by EMD of General Motors. The failures were caused by severe corrosion of the solder, which sealed the tubes to the tube sheets. These failures occurred in the raw water side of the coolers. The corrosion inhibitor in use was Calgon CS, a borated-nitrite type inhibitor. The manufacturer of this type of inhibitor has recommended the use of hard solder in CS treated systems. EMD does not recommend the use of Calgon CS since the puddle solder used in EMD radiators and oil coolers is a soft solder of lead-tin composition.

Information Notices

IN 79-23: Emergency Diesel Generator Lube Oil Coolers

Water intrusion in the lube oil system resulted in trips of both diesel generator units during their surveillance tests. The water intrusion was caused by tube sheet failure in the lube oil coolers. The failures were cracks around the outer periphery of the tube sheets. Coolers were replaced, however, the failure mechanism has not been determined.

IN 85-08: Industry Experience On Certain Materials Used In Safety-Related Equipment

This information notice was issued to provide licensees and construction permit holders with information pertaining to the behavior of certain materials used in safety-related equipment. Three of the materials were elastomers and one related to a coating applied to the Diesel Oil Storage Tank. During final inspection of the diesel oil storage tanks at Limerick Generating Station, the epoxy phenolic coating on portions of the interior surface of three of the four Unit 1 tanks was observed to have extensive peeling and flaking. The specification for Limerick Station required that the entire interior surface of the tanks be coated with an inorganic zinc primer to a thickness of between 2.0 mils and 4.0 mils. On top of the zinc primer, an epoxy phenolic coating was applied to a minimum of 12 mils and a maximum of 18 mils dry film thickness. Philadelphia Electric Company stated that there are two factors that may have contributed to the coating failure: (1) chemical incompatibility between the zinc primer and the epoxy coating, and (2) improper curing of the zinc primer. Subsequent investigation revealed that the zinc in the primer coat may react adversely with diesel fuel when exposed over a long period of time.

Products of this reaction are often soluble when the fuel is at room temperature, but may degrade into insoluble gums as the fuel passes through the hot injectors and intake manifolds of a diesel engine, and thus may result in degraded performance as the engine is operated over a period of time. The Philadelphia Electric Company proposed corrective actions to provide sufficient protection against the deficiencies described above and also against any internal corrosion of the tanks as a result of internal condensation. The interior surface of the tanks will be sandblasted to white metal and recoated with a substitute epoxy phenolic coating applied directly to the white metal.

IN 86-73: Recent Emergency Diesel Generator Problems
This notice is to alert addressees to vibration-induced fuel line wear and of a deficiency in the design of the field flash circuitry on nuclear plant emergency diesel generators. While conducting diesel generator testing in early May 1986 at Nine Mile Point Unit 2, it was discovered that diesel fuel lines had experienced extensive wear and fuel leaks in the area of the clamps that mount the fuel lines to the diesel engine. Fuel line damage was caused by vibration from the diesel engine and fuel system pulsation induced by rapid, repeated cycling of a fuel system relief valve. This valve relieves from the low pressure fuel system via a cooler to the fuel day tank to control low pressure fuel system pressure. The manufacturer proposes to correct the problem by inserting plastic sleeves between the fuel line and, its hold down clamps and installing a dashpot on the relief valve to dampen its operation.

IN 89-07: Failures of Small Diameter Tubing in Control Air, Fuel, Oil, and Lube Oil Systems Render Emergency Diesels Inoperable
This information notice indicates that small diameter tubing installed on EDGs or other components are susceptible to vibration-induced failures which could render the component inoperable. The vibration-induced failures may appear as cracking or breaks as well as holes and wall thinning caused by rubbing of components. These failures are not limited to specific manufacturers, systems, or materials. The common underlying cause of the failures is the inadequate design or installation of supports for the small diameter tubing in a vibrating environment.

IN 91-46: Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems
This information notice alerts the utilities about problems encountered with the emergency diesel generator fuel oil delivery systems, ranging from a delivery system maintenance issue (i.e., inappropriate painting clogging the injection nozzles) to standards and test specification for fuel oil quality and degradation/deterioration over time. This information notice does not address any aging related degradation issues, however, the resultant conditions can cause aging effects and inability of the systems to perform their intended functions.

IN 93-48: Failure of Turbine-Driven Main Feedwater Pump to Trip Because of Contaminated Oil
This information notice alerts the utilities about potential problems resulting from suspended particles in the control oil in the trip system for turbine-driven main feedwater

pumps. Suspended particles in the oil created a flow blockage in the control oil pump valves. This prevents proper drainage of the trip system. Most of the accumulated particles were small, but some were up to 6 mm (1/4 in.) long. The condition resulted in accumulation of suspended particles in the low flow areas of control oil ports over a period of time. The maintenance program should include flush of possible suspended particle buildup areas. This Information Notice addresses a concern that affects the active function of the oil hydraulic system and equipment that is probably outside the scope of license renewal at most plants.

IN-94-58: Reactor Coolant Pump Lube Oil Fire
This information notice was issued to alert the licensees of a problem that may exist with the oil collection system for the lube oil system components of reactor coolant pumps. The oil collection system must be designed in such a way that it can properly catch and route to a safe location the oil leakage from the RC pump lube oil system. The piping and components around the RC pumps are normally above the lube oil ignition point, therefore, a fire could start if the lube oil came in contact with a hot component. In one of the cases cited in this information notice a PVC pipe carrying oil from the lube pump to the RC motor cracked and spilled oil on a hot pipe causing an oil fire in containment. PVC tube was used to electrically isolate the RC motor from the lube oil pump.

IE Bulletins
No IE Bulletins were identified that relate to the oil and fuel oil systems.

Generic Letters
GL 83-26: Clarification of Surveillance Requirements for Diesel Fuel Impurity Level Tests
This generic letter provides clarification for the surveillance requirements of diesel fuel impurity levels. Fuel impurity levels may affect corrosion. Specifically, programs to monitor purity levels may be part of license renewal credited program (similar to chemistry program).

3.7.3 Summary of Generic Correspondence

A majority of the significant generic correspondence issued was concerned with either water intrusion or lack of adequate oil and fuel oil purity control. Water intrusion into oil or fuel oil systems can result in a corrosive environment and is specifically addressed in the tool logic. IN 79-23 and CR80-11 deal with specific failures of a certain type of lube oil cooler soldered tube to tubesheet connection in the presence of Calgon CS corrosion inhibitor. This failure is manifested on the treated water side of the lube oil coolers and is addressed in the Heat Exchanger tool (Appendix G).

Contaminants do not typically affect the license renewal intended functions (i.e., pressure boundary structural integrity), however, in combination with moisture intrusion, they can accelerate corrosion of the system materials. Since there are many sources of moisture in these systems, it is assumed that if moisture intrusion has occurred, contamination is also present. As indicated in IN 93-48, particle contamination can also result in the failure of certain trip functions in oil control systems. These trip functions are part of active functions that are outside the scope of this tool.

IN 85-08 discusses peeling and flaking of epoxy phenolic coatings on the lower portion of diesel fuel oil storage tanks. In addition to the loss of corrosion protection of the tank material, this coating could potentially result in impeded fuel oil flow. Although epoxy phenolic coatings are not specifically discussed in this tool logic, tank liner/coating integrity verification for all coatings/liners is included.

The diesel generators are very large engines, which vibrate when operating. Connected to these large vibrating machines are numerous small bore pipes and instruments lines. Many of these attached pipes include diesel fuel oil and lubricating oil lines. In addition, the fuel oil and lube oil pumps in the supply systems also vibrate when operating. IN 86-73 and IN 89-07 address specific failures of these attached lines. Some cracking may be a result of inadequate support design for small bore piping or the cyclic nature of the operation of diesel generators and their support systems. Logic is included in this tool to address vibration concerns.

IN 94-58 addresses inadequate design considerations in PWR reactor coolant pumps oil collection systems and is not an aging issue.

4. FLOW DIAGRAM DEVELOPMENT

4.1 Assumptions

The assumptions used to develop the evaluation flow chart are provided below.

1. The number of additives and by-products found in oil and fuel oil products make it difficult to consider all possible naturally occurring or manufacturer added contaminants. The effect of these additives on various forms of corrosion such as SSC, pitting, and crevice corrosion may not be well known, therefore, contaminants that can cause corrosion are assumed to be present. These contaminants include sulfates, halides, and chlorides.

2. Nonmetallic material such as plastic, rubber, and other “consumable” items (gaskets, O-rings, seals, and sealing compounds) are not subject to aging management review (see section 2.2 of the Implementation Guideline).

3. Crevice corrosion requires some type of crevice (two surfaces approaching each other within a few thousandths of an inch or less). It is unreasonable to expect an evaluator to respond to a question of whether or not a crevice exists within a system or component. The logic, therefore, will assume conservatively that the potential exists for crevices in all components and systems.

4. Some aging effects are the result of mechanisms that require the material to be under stresses that are difficult to predict. It would be unreasonable to expect an evaluator to establish the presence of stresses resulting from the manufacturing process or post installation welding for every component under consideration. In these instances, the logic will conservatively assume that the stress exists.

5. Macroorganisms (e.g., barnacles, mussels, clams, and algae) are assumed not to be present to any significant degree for the purposes of this tool. Macroorganisms are only present in raw water systems.

6. Microbiologically Induced Corrosion (MIC) can only propagate at low temperatures (typically assumed to be at or below 200 °F). It is assumed that, for the oil and fuel oil applications included in this tool, the low temperatures of the fluids are such that they support the propagation of MIC.

7. Hydrogen damage is typically only a concern in the petroleum industry during the refining process [7]. A review of available industry data and AMRs [9, 12, 13] indicates that hydrogen damage is only a concern where cathodic protection is used and the voltage is improperly set [12].

8. If this tool is used to evaluate the Reactor Coolant Pump (RCP) oil collection system at PWRs, it should be noted that at times the oil collection system can be subjected to

condensation/moisture, leaking oil, and the containment atmosphere. No single tool is likely to contain all the logic to evaluate these particular components. Appropriate raw water, treated water, gas or other tools should be applied to assure that all aging mechanisms are evaluated.

9. Failure of Epoxy Phenolic coatings on fuel oil storage tanks due to flaking and peeling can result in corrosion and/or plugging of fuel lines. Where the logic applies a determination as to whether the liner/coating integrity is verified, it is assumed that this includes consideration of this type of coating.

10. Various incidences of vibration caused failures have occurred in diesel lube oil and fuel oil systems. These failures are documented both in the NPRDS equipment failure history and in NRC correspondence. Although these failures are attributable primarily to inadequate design considerations or maintenance practices, they are likely to continue into the license renewal period if not addressed. Consideration of vibration is included in the tool logic. However, each plant utilizing this tool should determine (based on specific plant history, original design methods, maintenance history, etc.) whether or not vibration is a concern for that particular plant.

4.2 General

The mechanical tools are intended to provide an efficient method to identify applicable aging effects for systems and components that are required to undergo an aging management review in compliance with the license renewal rule. Implementation of these tools at the various sites will result in the identification of plant equipment and aging effects that must be managed or, justification that management of aging effects is not required, during the renewal period. Demonstration of the adequacy of aging management programs is outside the scope of this tool.

These tools will identify potential aging effects and also direct the user to areas in the system where these effects might preferentially occur. The discussions in Section 3 identified aging mechanisms and their associated aging effects, which can occur in the oil and fuel oil system equipment addressed by these tools. The user is guided through logic to determine whether these effects are significant based on specific system or component materials, environment and/or operating conditions. These tools address the effects of aging on materials that are in oil or fuel oil environments. They are organized such that those using the tools do not require detailed knowledge of aging mechanisms or their effects. The logic does, however, require that the user be familiar with the materials of construction, applicable environments, and system operating conditions.

The evaluation logic groups aging effects such as loss of material and cracking to efficiently resolve the disposition of equipment. Implementation of the tools, in effect, documents the resolution of aging mechanisms, the resultant aging effects, and provides a link to the program evaluations and Aging Management Review (AMR) phase. The results not only identify the effects which must be managed but, given the screening criteria, can be a valuable input when determining how and where to implement aging management programs.

4.3 Tool Descriptions

Figures 1 and 2 contain the logic and criteria to evaluate aging effects for materials in a lube oil or fuel oil environment, respectively. The materials and environments covered by these tools are described in Section 2.0 of this tool.

As discussed in Section 3.2.3, the chosen approach to address the loss of pressure boundary integrity resulting from vibration is a plant specific issue. Some plants will take the position that vibration induced failures typically occur early in plant life and are a design/installation/maintenance issue rather than an aging effect. Other plants will include vibration induced failures as an aging effect based on either plant specific or industry wide failure history. The shaded portion of both the lube oil and the fuel oil logic is included as an "option" to allow each utility to address vibration in a way that best fits into their specific aging management program.

The logic is very simple by focusing attention on components and piping that are in close proximity to rotating or vibrating equipment. No specific distances are identified since they will vary based on the type of equipment and the material used. In some instances vibrating failures may occur several feet from a vibrating component. In other situations piping or other component rigid supports, if very close to the vibration source, may result in high levels of fatigue at this support.

4.3.1 Lubricating Oil

Based on the number of vibration attributable failures in the NPRDS failure search, the shaded area of the oil tool directs the user to identify those components in locations in close proximity to pumps and/or other vibrating equipment. As indicated above, use of this vibration logic is optional and dependent on plant specific issues.

Chapter 3 of this tool discusses the various aging mechanisms and it is concluded that MIC and SCC are not significant aging mechanisms in lubricating oil systems. Based on Chapter 3, the referenced material, the industry failure data search and generic communications review, the other significant aging effects are not expected to occur in lubricating oil systems unless external contamination of the lubricating oil has occurred. The remainder of the lubricating oil tool logic, therefore, asks whether the potential for water contamination exists. Even if water contamination occurs, significant aging effects would only be expected where the water contamination can settle or "pool" to result in a potential corrosive environment. Oil reservoirs and the bottoms of heat exchangers are examples of areas where water can settle. If the likelihood of water contamination and subsequent settling does not exist for equipment, aging effects are not likely to occur. Equipment in locations where settling or pooling of water contamination is possible may be coated or lined to protect the material from the effects of corrosion. As long as periodic liner verification is conducted, linings/coatings can be credited with preventing corrosion/cracking of the material, as reflected in the next tier of the tool logic.

The remainder of the logic focuses on the aging effects that may occur with materials in locations subject to water contamination and subsequent settling or pooling of the water. General corrosion of carbon and low-alloy steels and cast iron (as discussed in Section 3.1.1 of this tool) is likely in a pooled water environment. Pitting and/or crevice corrosion is also a potential aging effect in these locations and is applicable to all materials covered by this tool logic.

Although the design of most equipment and components precludes galvanic corrosion, wherever dissimilar materials are in contact, the potential for corrosion does exist. In a corrosive environment, contact, or close proximity of materials that are distant in the galvanic series , can result in a loss of material of the more anodic material. This is usually a concern where carbon, low-alloy steel, or cast iron is in contact with stainless steel. Heat exchangers are particularly susceptible because of the various materials of construction and environments. The tool logic requires a detailed knowledge of the various materials of construction for the evaluation of the likelihood of galvanic corrosion. When applying the logic, the design features used to control galvanic corrosion should be considered. Sacrificial anodes, coatings, and separation devices can be used to minimize the likelihood for galvanic corrosion.

The last tier of the logic addresses selective leaching. Only gray cast iron and yellow brass are affected.

4.3.2 Fuel Oils

Based on the number of vibration failures identified by the NPRDS failure search, the shaded area of the oil tool directs the user to identify those components in locations in close proximity to pumps and/or other vibrating equipment. As indicated above, use of this vibration logic is optional and dependent on plant specific issues.

Microorganisms can live in fuel oil with only minute amounts of water and, therefore, methods to control microorganisms must be implemented. There are various methods to control MIC, the addition of a biocide being one example [6]. Cathodic protection has also been demonstrated to prevent MIC and is particularly effective when used in conjunction with lining or coating of the component [6]. The next branch in the logic diagram eliminates the effects of MIC from further consideration if a means of prevention is used. The effectiveness of the approach must be verified to assure adequate protection.

Cathodic protection has been known to result in hydrogen damage when the voltage has been improperly set [12]. No specific acceptance criteria can be listed since each system and application is unique. The tool logic addresses the likelihood of hydrogen damage in situations where cathodic protection is used.

Lining or coating of plant components (e.g., fuel oil storage tanks, and piping) has proven effective in avoiding corrosion. Therefore, if a lining or coating is used, no aging effects are identified. The logic also assumes that linings/coatings have appropriate inspections and/or liner integrity verification. Epoxy Phenolic coatings are particularly vulnerable to flaking and peeling of the coating

The remainder of the logic concentrates on the conditions that are necessary in fuel oil systems for a corrosive environment. Since the corrosion mechanisms require an electrolytic medium, it is assumed that water contamination can occur in the fuel oil systems. When water contamination is present, significant corrosion is only expected where the water can settle or pool. When water contamination does occur, it tends to collect in stagnant or low flow portions of the system (e.g., tanks and reservoirs). It can settle in low flow areas such as heat exchangers where the oil and water separate, with the water gradually moving to the lower areas. The low flow typically seen in these systems may not be sufficient to flush the pooled water rendering a corrosive environment

This logic tool addresses many different materials and not all are affected by the various aging mechanisms. The logic at the bottom of the tool focuses on the various corrosion mechanisms that may occur and identifies the various materials affected by these mechanisms.

In a wetted environment, general corrosion of carbon and low-alloy steel as well as cast iron is a concern. Pitting and/or crevice corrosion is also a concern for all materials covered by this tool.

Galvanic corrosion is only a concern where materials are in contact and are galvanically distant from each other. Only the more anodic material is affected (e.g. carbon steel is affected when in contact with stainless steel). The severity of the resultant loss of material is determined by the surface area of material in contact and the nature of the corrosive environment.

Selective leaching in a wetted environment can occur with no other contaminants present. The logic tree addresses this issue identifying yellow brass and cast iron as the only materials susceptible to this loss of material effect.

Stress-corrosion cracking only affects a subset of materials used in fuel oil systems. All stainless steels within the scope of this tool are considered susceptible. Pure aluminum is not susceptible, however, aluminum alloys containing more than 12% zinc or more than 6% magnesium are susceptible. Of the copper alloys covered by this tool, only those (which includes admiralty metal) containing greater than 15% zinc (including admiralty and Muntz)are susceptible to SCC.

Figure 1 – Lube Oil Tool

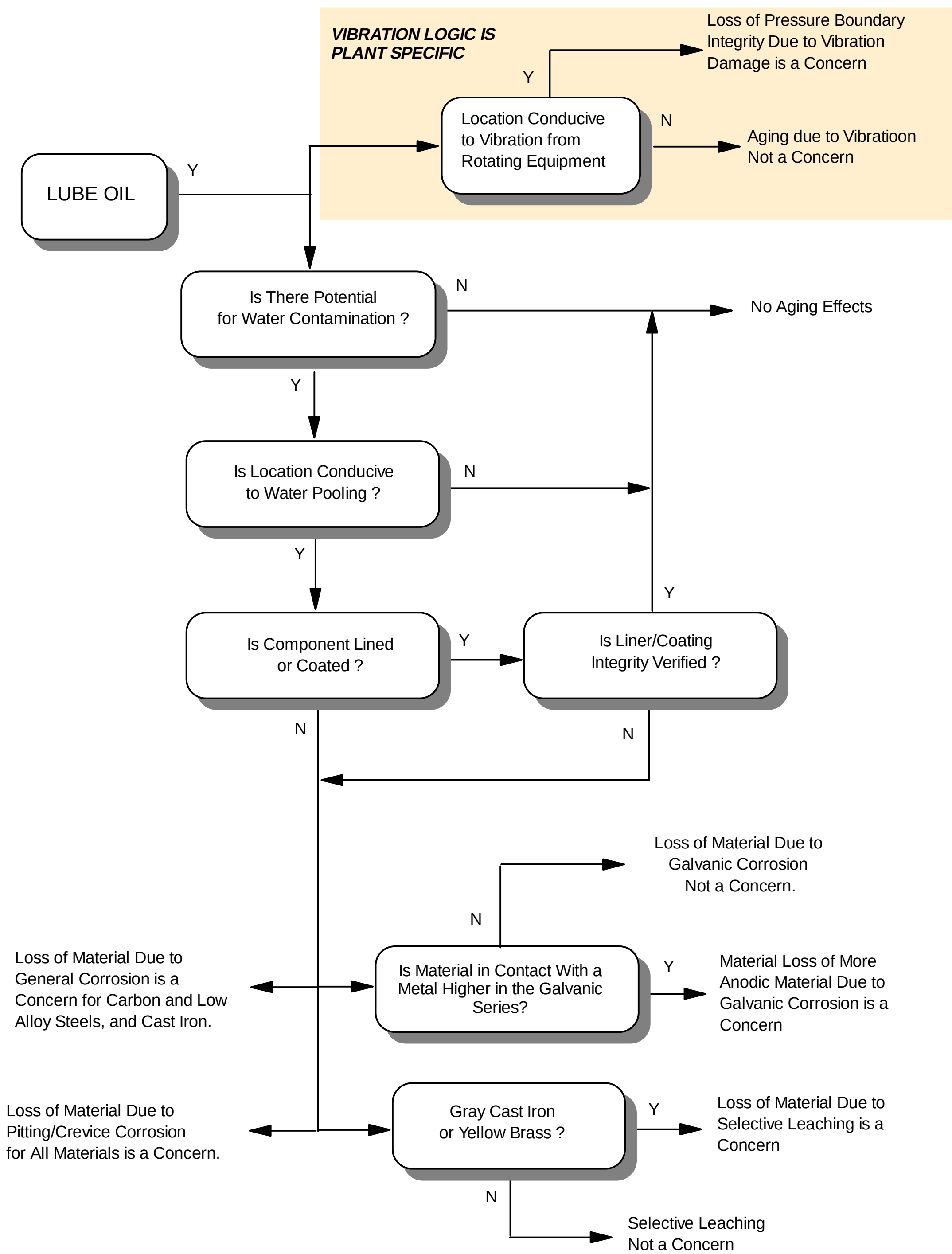
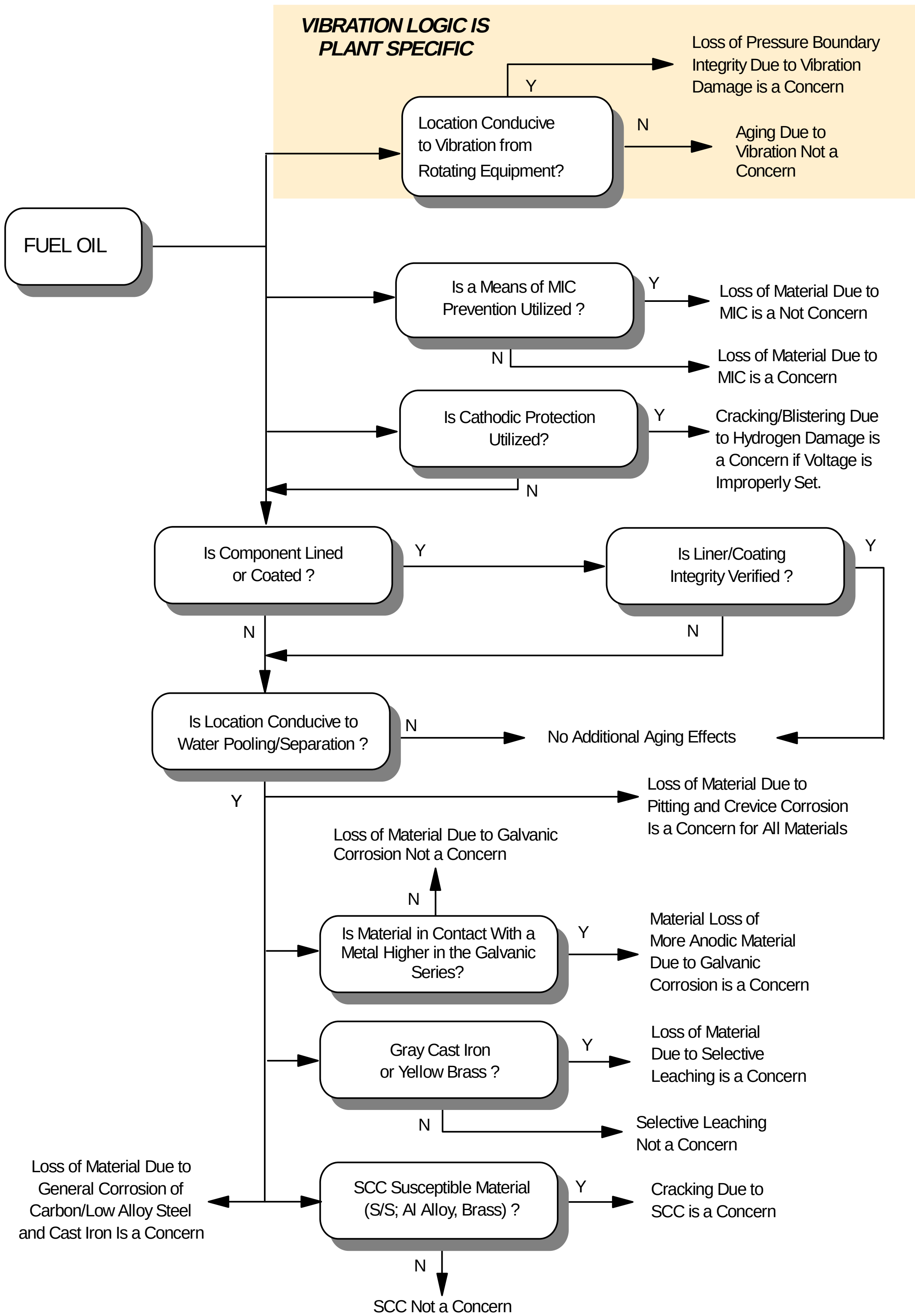


Figure 2 – Fuel Oil Tool



5. CERTIFICATION

This appendix is an accurate description of aging effects of various metals in an oil or fuel oil environment prepared for the B&W Owners Group Generic License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

D. J. Firth 8/14/99

David J. Firth Date
GLRP Project Manager

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Appendix D - Gas

The Gas Tool provides a methodology for identifying the aging effects in portions of systems and components that may be subjected to an internal environment of a variety of different gas mixtures. The environments covered by this tool include atmospheric air, dry/filtered instrument air, nitrogen, carbon dioxide, hydrogen and helium. This tool is designed for use in any component with a gas internal environment which includes, but is not limited to; compressed air systems, instrument air systems, diesel air start systems, air cooling systems, standby gas treatment systems, combustible gas treatment systems, HVAC/room cooling systems, hydrogen systems, nitrogen systems and dry spent fuel storage systems. It can also be used on portions of tanks or other components normally subjected a gas environment such as; core flood tanks, borated water storage tanks, condensate storage tanks, makeup tanks, etc. The various materials covered in this tool consist of carbon and stainless steels, nickel-base alloys, galvanized steel, copper alloys (brass, bronze, and copper-nickel), aluminum and cast iron.

For the most part degradation mechanisms and subsequent degradation effects require a moist environment (or pooled liquid), in addition to oxygen and/or a caustic substance. These requirements for aging effects are essentially applicable for all materials covered, therefore, this tool initially establishes whether or not the conditions exist for aging effects to be demonstrated regardless of the material. The tool then continues to apply various logic to identify specific aging effects for the various materials covered. The result is a tool that adequately identifies applicable aging effects for materials exposed to gas environments.

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1. INTRODUCTION

The scope of the Gas Aging Management Tool is intended to cover numerous environments and many different materials. In addition to including coverage of typical gas systems such as instrument air, compressed air, diesel starting air, nitrogen, hydrogen, carbon dioxide, helium, and BWR off-gas systems, this tool includes the logic necessary to evaluate portions of equipment normally exposed to a gas environment such as the nitrogen blanket in core flood tanks, the hydrogen environment in makeup tanks, etc. This tool also includes the logic to evaluate various portions of HVAC systems, which includes but is not limited to control room/ safety related area cooling systems, as well as containment air sampling systems.

This gas tool provides a logical and consistent approach to identifying applicable aging mechanisms for materials subjected to an air/gas environment. Due to the various plant modes of operation, varying environments and multiple system functions, the application of one Mechanical Tool may not be sufficient to completely identify all significant aging concerns. Some plant components are alternately subjected to gas and fluid environments depending on the system mode of operation. Fluid storage tanks typically have surfaces which are not subjected to the fluid environment of the tank. Equipment such as heat exchangers are often open to the environment for extended periods of time during repair activities. Other scenarios include equipment shutdown conditions under which components may be placed in dry lay-up in either a controlled or non-controlled environment. In cases such as those listed above, one single Mechanical Tool may not provide all necessary information required to completely evaluate the equipment. Therefore, the use of more than one tool may be appropriate to assure that all equipment environments are covered and all potential aging concerns are identified.

The various materials used in parts of the above described components and systems typically include a number of metals and alloys. Carbon steel and stainless steel are typically used for piping, tanks, pressure vessels and accumulators. Portions of air and gas system piping and fittings include carbon steel, stainless steel, brass, bronze, aluminum and cast iron. Ductwork for air supply systems may be constructed of galvanized steel and may include nonmetallic material and can include a variety of metals. Nonmetallic materials such as gaskets, packing, O-rings, and seals are not covered within this tool (see Section 2.2 of the Implementation Guideline).

The wide range of materials used for these systems, and the diverse environments that they are subjected to, complicate the development of an all encompassing tool. This is ameliorated by the lack of appreciable contaminates in most of the systems, which results in an environment that is not conducive to the onset and/or propagation of most degradation mechanisms.

Although it is intended for use with various gas systems and components, an integral part of the development of this tool is consideration of industry failure data contained in the NPRDS data base. This data base is limited to information for the "reportable" systems and not all systems for which this tool is designed are reportable. When using this tool for non "reportable" systems or for systems which are not within the license renewal scope, this tool should be supplemented with other industry or plant specific equipment failure history to assure completeness.

2. MATERIALS AND ENVIRONMENTS

The Gas Tool is intended to assist the evaluator in determining locations within gas systems that may be susceptible to one or more of the following aging effects: cracking, loss of material, reduction in fracture toughness, and distortion. This tool is also intended to cover portions of equipment and/or systems that are in contact with a gas environment (e.g., core flood tank nitrogen blanket, fuel oil tank air environment and makeup tank hydrogen blanket).

The materials addressed in this tool are discussed in Section 2.1 and the various environments are defined in Section 2.2.

2.1 Materials

The materials addressed in this tool include (1) wrought and cast stainless steels, including weld metals and stainless steel cladding, (2) nickel-base alloys, including nickel-base alloy weld metal, (3) carbon steels and low alloy steels, (4) aluminum, (5) cast iron, (6) copper alloys (brass, bronze and copper-nickel), and (7) galvanized steel.

2.1.1 Stainless Steels

The stainless steels discussed in the Gas Tool are divided into the following categories: (1) wrought stainless steels, (2) cast stainless steels, (3) weld metals, and (4) stainless steel cladding. Each is discussed below.

Wrought Stainless Steels
Wrought stainless steels are commonly divided into five groups: (1) austenitic, (2) ferritic, (3) martensitic, (4) precipitation hardening, and (5) duplex stainless steels. Definitions of the aforementioned groups of stainless steels are provided in Reference 1 and are not repeated here. Martensitic and precipitation hardening stainless steels are typically used for bolting, valve stems, and pump shafts, and are not evaluated in this tool. [Note: valve stems and pump shafts are not subject to aging management review in accordance with the discussion in Section 2.0 of the main document.] Bolted closures are addressed in Appendix F.

Cast Stainless Steels
The cast stainless steels addressed in the Gas Tool all contain ferrite in an austenitic matrix (i.e., CF series) and are commonly known as cast austenitic stainless steel (CASS). Typical alloys used in nuclear applications include CF-8 and CF-8M which are cast counterparts of wrought Types 304 and 316, respectively. Other castings include CF-3 and CF-3M which are cast counterparts of Types 304L and 316L, respectively. Alloys CF-3M and CF-8M are modifications of CF-3 and CF-8 containing 2% to 3% molybdenum and slightly higher nickel content to enhance resistance to corrosion and pitting.

Stainless Steel Weld Metal

The welding materials used to join stainless steels depend upon the type of material being joined. For example, Type 304 wrought austenitic stainless steels may be joined using either gas metal-arc welding (GMAW), submerged-arc welding (SAW), or shielded metal-arc welding (SMAW) processes with a Type 308 electrode or welding rod. The various welding processes used to join wrought stainless steels include SMAW, SAW, GMAW, gas tungsten-arc welding (GTAW), and plasma-arc welding (PAW). Flux core arc welding (FCAW) may have been used but to a lesser extent. Stainless steel welding processes typically used include SMAW, GTAW, GMAW, and electroslag [1].

The weld metal is assumed to be equivalent to the wrought austenitic stainless steels with respect to the discussions of loss of material and resistance to cracking (initiation) in Section 3.0, however, it should be noted that welds are typically more resistant to SCC because of ferrite content. Also, the strength and toughness of selected stainless steel weld metals used to join wrought stainless steels were shown to vary depending upon the welding process used [17]. For example, flux welds, such as SAW and SMAW, were shown to provide joint properties with higher strength and significantly lower toughness than the surrounding base metal. Higher strength of the weld metal results in enhanced load bearing capacity compared to base metal; lower toughness of the weld metal may result in a reduced ability to support structural loads if the weld metal cracks. The strength and toughness of non-flux welds, such as GMAW and GTAW, were shown to be similar to the surrounding base metal.

Stainless Steel Cladding Material

Stainless steel cladding within the scope of the license renewal rule (and thus within the scope of this Gas Tool) is exposed to borated water or a moist gaseous environment and are typically austenitic stainless steel. Cladding may take the form of weld deposit or stainless steel plate that is either explosively applied or rolled onto carbon or low-alloy structural steel. A detailed description of weld deposit cladding is provided in Section 3.0 of Reference 2. The cladding is assumed to be equivalent to the wrought austenitic stainless steels with respect to the discussions of loss of material and resistance to cracking in Section 3.0.

2.1.2 Nickel-Base Alloys

The nickel-base alloys that are typically used for nuclear applications include nickel-chromium-iron alloys such as Alloy 600 and Alloy 690. These materials are used primarily for their oxidation resistance and strength at elevated temperatures. The applications are typically restricted to the reactor coolant system (e.g., reactor vessel CRDM nozzles), but may also be found in selected non-Class 1 components such as the core flood tanks. In addition, Alloy 600 may also be used in fasteners which are discussed in Appendix F. Other nickel-base alloy materials such as nickel-copper and nickel-copper-molybdenum alloys are not evaluated in this tool.

Welding of nickel-chromium-iron alloys is typically performed using arc-welding processes such as GTAW, SMAW and GMAW [1]. Submerged arc welding may also be used provided the welding flux is carefully selected. Alloy 82 and Alloy 182 are typical filler metals used to join Alloy 600 components to carbon or alloy steel vessels in the reactor coolant system. Alloy 82/182 are also used as cladding in selected components within the reactor coolant system. In addition, Alloy 52 and Alloy 152 are typical filler metals used to join Alloy 690 components to carbon or alloy steel vessels in the reactor coolant system.

2.1.3 Carbon Steel and Low Alloy Steel

Carbon steel is used throughout nuclear plants in various applications. It is used where high corrosive resistance is not required and is the material of choice for pumps, valves, tanks and fittings in most plant water, air, and gas systems. The term carbon steel as used in the aging evaluation applies to all carbon and low alloy steels.

2.1.4 Aluminum

Aluminum has limited use in nuclear plant applications, however, due to its high resistance to corrosion in atmospheric environments, in fresh and salt water, and in many chemicals and their solutions, it can be found in various gas system applications.

Typical applications of aluminum at nuclear plants are in various instruments in gas and fluid systems. Aluminum may also have limited use as ductwork in air supply systems.

2.1.5 Cast Iron

The term cast iron identifies a large family of ferrous alloys. Cast iron typically contains more than 2% carbon and from 1 to 3% silicon. The four basic types of cast iron are (1) white iron, (2) gray iron, (3) ductile iron, and (4) malleable iron. White cast irons have high compressive strength and good retention of strength and hardness at elevated temperature, but they are most often used for their excellent resistance to wear and abrasion. Gray cast iron has several unique properties that are derived from the existence of flake graphite in the microstructure. Gray iron can be machined easily at hardnesses conducive to good wear resistance. It has outstanding properties for applications involving vibrational damping or moderate thermal shock. Ductile cast iron is similar to gray iron in composition, but during casting of ductile iron, magnesium and cerium is added to the molten iron to give the final product higher strength and ductility. Malleable iron has similar properties to ductile iron, however, it is more expensive to manufacture and is only used where thin section castings, and for parts requiring maximum machinability or where a high modulus of elasticity is required.

This Gas Tool evaluates only the more widely used white and gray cast iron alloys. Although comprising two general categories, various alloying elements can and are added to cast iron alloys to promote an array of hardness, corrosion resistance, heat resistant and abrasion resistance properties [1].

2.1.6 Copper Alloys (brass, bronze, and copper-nickel)

Bronze and brass are copper alloys using predominantly copper, tin, and zinc with various other alloying agents present in differing amounts. Brass is an alloy of copper and zinc with other metals in varying lesser amounts. Bronze is any of various alloys of copper and tin, sometimes with traces of other metals. Other copper alloys are used in other applications most notably copper nickel alloys in condenser and heat exchanger tubing material.

Brass and bronze products are available in both cast and wrought product forms with most alloy compositions available in both. Brasses and bronzes containing tin lead and/or zinc have only moderate tensile and yield strengths and high elongation. Aluminum bronzes, manganese bronzes and silicon brasses/bronzes are used where higher strength alloys are required. Various alloys of brass and bronze are used in a number of applications including fire protection sprinkler systems, compressed air, and instrument air systems.

2.1.7 Galvanized Steel

Galvanized steel is produced by taking steel sheets and coating them with zinc or iron-zinc alloys. The corrosion resistance of the galvanized steel is directly proportional to the amount of zinc in the coating. The metallic zinc is applied to iron and steel by one of three processes: hot dip galvanizing, electro-galvanizing or zinc spraying. A majority of the galvanized steel sheet metal is produced by the hot dip process [P. 4-26, Ref. 1]. The hot dip process is one in which an adherent protective coating of zinc and iron-zinc alloys is applied by immersing the steel in a bath of molten zinc. This process utilizes a series of layers with each successive layer containing a higher concentration of zinc. This produces a gradual transition through the coating with no discrete line of demarcation.

Galvanized steel is used where corrosion resistance in at atmospheric environment is required. The relatively low production cost and appearance make galvanized steel an ideal choice for air system ducts [P. 4-26, 4-94, Ref. 1].

2.2 Environments

This Tool includes a majority of the gaseous internal environments to which components within the scope of license renewal may be subjected. Numerous components may be subjected to different gaseous environments depending on plant and system operating conditions. The various gaseous environments covered by this tool are described below.

2.2.1 Air

Air is composed of mostly nitrogen and oxygen with smaller fractions of various other products and inert gasses. The internal surfaces of a majority of components are at some time exposed to air as a result of either exposure to air or as a component of a forced air system. External contact with air is described in Appendix E. Where air is the intended internal fluid (e.g., compressed air and instrument air systems), it is supplied in either its natural state or in a "dry" condition. Oil may also be present in compressed air due to the method of compression.

2.2.2 Nitrogen

Nitrogen is an inert gas that is used in many nuclear plant applications to place components in a dry lay-up condition or to provide an overpressure where low oxygen content is desirable. Primary storage of nitrogen is in tank(s) as a very low temperature liquid and is usually preheated prior to use in plant components. Intermediate storage is typically in heat traced piping or tanks. Experience has shown that commercial grade nitrogen is provided as a high quality product with little if any external contaminants [12].

2.2.3 Hydrogen

Hydrogen has limited use in nuclear plants as an oxygen scavenger to control primary water chemistry. In PWRs the reactor coolant makeup tank contains a hydrogen blanket to scavenge oxygen from the makeup fluid. Hydrogen is injected into the reactor primary fluid in BWRs as a means to control oxygen content. Hydrogen is also used as a coolant for the electrical generator, however, the generator cooling system is not within the scope of license renewal and is not a reportable system in NPRDS. Although this tool can be used as a guide for identifying aging effects in the generator cooling system, the absence of failure data requires that plant specific and other industry data be used to identify all appropriate aging effects in that system.

Hydrogen can also be present as a result of a corrosion process or due to electrolysis [5]. However, an extremely corrosive environment is necessary for the generation of significant amounts of hydrogen and such an environment does not typically occur in the air and gas systems covered by this tool.

2.2.4 Carbon Dioxide

Carbon dioxide is a colorless, odorless incombustible gas. It is used in nuclear plants as a fire suppression gas for several major plant components including diesel and hydro generators. The carbon dioxide systems of interest at nuclear plants contain dry carbon dioxide in gaseous form. Without the presence of moisture, this gaseous carbon dioxide is not a contributor to corrosion or other aging effects [1].

2.2.5 Helium

Helium is a colorless odorless and inert gas and, as such, demonstrates no chemical reactivity. As a result, helium in its pure form has no impact on corrosion or corrosion rates and, even as a contaminant, does not affect the corrosion rates of materials. Corrosion covered by this appendix is impacted by the presence of oxygen, moisture and other contaminants. These conditions are required for the advancement of corrosion regardless of the presence of helium.

2.2.6 Fluorocarbons (Freon)

Fluorocarbons constitute a large family of fluorinated hydrocarbon compounds that exhibit similar chemical properties and a wide range of physical characteristics. Their inert character and the range of their vapor pressures, boiling points and other physical properties makes them especially well suited for use as the working fluid in refrigeration and air conditioning systems, and as a propellant for pressure-packaged products. The fluorocarbons covered by this Mechanical Tool are inert, nonflammable, colorless and relatively nontoxic. Fluorocarbons show no appreciable decomposition at temperatures up to 400F and oxidize only with extreme difficulty and at very high temperatures. The fluorocarbons are noncorrosive to all common metals except at very high temperatures. Water or water vapor in fluorocarbon systems will corrode magnesium alloys or aluminum containing over 2 per cent magnesium, however, such corrosion will neither be speeded nor slowed by the fluorocarbon presence [14].

The refrigerant systems covered by this tool are typically pressurized closed loop systems mixed with an oil lubricant. These systems contain in line refrigerant dryers for enhancement of both performance and corrosion prevention. Unless contamination of the closed system with moisture and/or sulfur occurs, the conditions necessary for internal pressure boundary degradation due to corrosion do not exist [15]. Pressure boundary failures due to vibration of rotating components such as compressors are addressed separately.

The EPA is requiring the use of replacements for freon. Some of the replacement gases are corrosive, flammable, and toxic. Any metal that is susceptible to chloride induced pitting and SCC mat exhibit degradation. If replacement gases are corrosive, then the systems where they are used must be screened for potential aging effects.

2.2.7 Fission Gases

The off gas systems at nuclear plants can be subjected to a variety of short and long lived radioisotopes, some of which can be highly corrosive. The off gas holdup tank and upstream piping are likely to contain iodine which is a halide and has corrosive tendencies similar to chlorine and sulfur. Other fission gases may also cause a highly corrosive environment. Although the off-gas system contains radioactive elements, the pressure boundary material is not subjected to neutron irradiation, which would be a concern for brittle fracture of the pressure boundary material. The other radiation levels present in the off gas system are not sufficient to cause a pressure boundary integrity concern.

3. AGING EFFECTS

The Gas Tool addresses aging effects that result from aging mechanisms described in various Aging Management Guidelines, technical references, and other industry sources. Where specific mechanisms are not applicable under the environmental and material conditions covered by this tool, justification is provided for a "not applicable" determination. For those effects that are applicable, a detailed discussion of the environmental conditions necessary for the effects to be manifested is included. Aging effects discussed below include loss of material, cracking, reduction of fracture toughness, distortion and loss of mechanical closure integrity. If one or more of the aging mechanisms is credible, then the aging effect is assumed to be applicable for the period of extended operation.

Each of the various aging mechanisms is discussed for all environments and for the materials listed in Section 2.1 and 2.2 of this aging tool. For the most part gasses provide an environment for aging effects only in the presence of moisture or other contaminants.

3.1 Loss of Material

3.1.1 General Corrosion

General corrosion is the result of a chemical or electrochemical reaction involving a material and an aggressive environment. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup [6]. At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are the factors that affect the corrosion of iron. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any practical extent [4]. Carbon and low-alloy steels as well as cast iron are susceptible to general corrosion; whereas stainless steels, nickel-base alloys, aluminum, copper alloys and galvanized steel are resistant to general corrosion [6].

Atmospheres can be classified as industrial, marine, or rural. Corrosion is primarily due to moisture and oxygen but is accentuated by contaminates such as sulfur compounds and sodium chloride. Corrosion of carbon steel on the seacoast is 400 to 500 times greater than in the desert area [8]. Steel specimens 80 feet from the shoreline corroded 12 times faster than those 800 feet away [8]. Sodium chloride is the primary contaminant of concern. Industrial atmospheres can be 50 to 100 times more corrosive than desert areas [8]. Locations where moisture condenses or accumulates and does not dry out for long periods of time can cause damage sometimes referred to as sheltered corrosion [8]. The definition of “a long period of time” is dependent on the material and the contaminants present. In some cases months may be required, in other cases several days may be sufficient to result in corrosion [8]. For the purposes of this logic tool, the rate of general corrosion will not be evaluated. That is, if the conditions exist such that the mechanism is plausible, it will be a concern regardless of the rate of corrosion.

The general corrosion effect is an electrolytic reaction and, regardless of the particular gas environment, depends on the presence of oxygen and moisture. Corrosion in a non-aqueous environment only occurs by direct chemical reaction and only at high temperatures well above those encountered in applications of this tool [1, P 4-89]. Nitrogen and carbon dioxide environments should have negligible amounts of free oxygen, therefore, corrosion of carbon steel and cast iron components in these environments should not be a concern. Hydrogen is used in the gas space of the makeup tank to scavenge oxygen from the reactor coolant fluid which results in an oxygen free environment. Any other system and/or components subjected to a hydrogen environment will also be free of oxygen and, likewise, will not be susceptible to corrosion.

The air environments within plant systems and components can vary from clean, dry air to moist, contaminated air whose purity is dictated by the source of the air. Portions of compressed and instrument air systems contain air that has been processed through dryers and filters which provide dry, oil free air to the downstream portions of the system. Moisture should not be a concern for these portions of systems and general corrosion would not be expected. However the NPRDS search (Section 3.7.1 of this report) identified numerous instances in which drying and filtering system failures resulted in the introduction of sludge, moisture and other contaminants to the “dry” portions of systems. The potential for the introduction of moisture and contaminants into the normally “dry” portions of systems must be considered when applying this tool.

3.1.2 Galvanic Corrosion

Galvanic corrosion occurs when materials with different electrochemical potentials are in contact in the presence of a corrosive environment [5]. Generally the effects of galvanic corrosion should be precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). Carbon and low alloy steels have lower potentials than stainless steels and would be preferentially attacked in a galvanic couple. Particular attention should be paid to component replacements and to carbon or low alloy steel system interfaces with stainless steel systems.

The severity of galvanic corrosion depends largely on the type and amount of moisture present. The atmosphere, and consequently air source, at or near the ocean will be much more conducive to galvanic corrosion. Galvanic corrosion does not occur when the metals are completely dry since there is no electrolyte to carry the current between the two electrode areas [4]. Any gas/moisture interface that contains dissimilar materials with significant potential differences may be susceptible to galvanic corrosion. Air systems can be susceptible to galvanic corrosion due to the different materials used and the potential for moisture in crevices and other low points of systems. Aluminum to brass connections as well as steel to copper connections are susceptible to galvanic corrosion [4].

3.1.3 Crevice Corrosion

Crevice corrosion occurs when a crevice exists in a component that allows a corrosive environment to develop within the crevice. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads [5]. Crevice corrosion is strongly dependent on the presence of dissolved oxygen and an aggressive environment such as the presence of S, Cl, F, or I. Oxygen is required for crevice corrosion initiation, however, once initiated oxygen is not required to continue the corrosion process. For systems with extremely low oxygen content (<0.1 ppm), crevice corrosion is considered to be insignificant [9].

In addition to oxygen and a moist environment, crevice corrosion requires an aggressive chemical species (e.g. halides, sulfates) and moisture to provide an environment severe enough to promote crevice corrosion. The contaminant level of these aggressive species in the gas sources used in nuclear plants is generally assumed not to be adequate to produce concentration levels that will promote corrosive effects, unless subjected to cyclic wet/dry conditions [1]. Moisture that either falls from the air as precipitation (covered in the external surfaces tool) or condensation on exposed surfaces can be considered a cyclic phenomenon if it can occur on the internal surfaces of material covered by this tool [5].

Providing that the oxygen content of the liquid environment is sufficiently controlled, maintaining an inert gas over-pressure on a tank will preclude the occurrence of crevice corrosion, due to the lack of oxygen. Components subjected to a stagnant environment with little or no oxygen control (such as tanks open to the atmosphere) provide an ideal situation for the progression of crevice corrosion. When a nitrogen over-pressure is placed on a tank (such as the core flood tanks), the concentration of the existing oxygen in the tank is reduced, however, the total amount of oxygen in the gas space has not changed. Unless a means of controlling this oxygen is present, the amount of oxygen is still sufficient to promote crevice and pitting corrosion. In a closed environment the gas space over a liquid will become saturated. However, unless there is a cycling of wetting/drying the contaminant level in the gas environment is assumed not to be sufficient to provide the aggressive environment necessary for crevice corrosion. Material at the gas to fluid interface is susceptible to crevice corrosion due to the possible wetting/drying cycling as the fluid level changes.

In summary, all materials are susceptible to crevice corrosion given a sufficiently narrow crevice in the presence of oxygen and a corrosive environment. Stainless steels and aluminum are notoriously susceptible to attack [7]. The level of oxygen for any specific application will vary, however, with any gas environment other than air, the oxygen content may be sufficiently low to preclude crevice corrosion concerns. Unless precluded by the use of dryers and/or filters, most gas environments contain some amount of moisture. Crevice corrosion is a concern where this moisture may pool in the presence of contaminants such as halides or sulfate.

3.1.4 Pitting Corrosion

Pitting is a form of localized attack that may progress through the wall of a component. It is one of the most destructive and insidious forms of corrosion because it causes equipment to fail due to perforation with only a small percent material loss of the entire structure. Failures are due to intense corrosion with failures sometimes occurring with suddenness [5]. Pits require a long incubation period before they are made evident by sudden failure. Pit growth is unique in that it is auto-catalytic or self-stimulating and self-propagating after it is initiated [7].

Pitting corrosion is an aggressive corrosion mechanism that is more common with passive materials such as austenitic stainless steels than with non-passive materials. All nuclear plant materials of interest are susceptible to pitting corrosion under certain conditions. Most pitting is associated with halide ions, with chlorides, bromides, and hypochlorites being prevalent [5].

3.1.5 Erosion and Erosion-Corrosion

Erosion is the loss of material due to a flowing fluid. Erosion-corrosion is a mechanism where fluid flow erodes or dissolves away the protective oxide or passive film of the metal, causing corrosion and re-oxidation. Impingement and solid particle erosion is caused by the impact of particles or liquid on a material. Elbows or T-type joints where the fluid flow changes direction are particularly susceptible to erosion [5].

This mechanism is not applicable to gas flow at the flow rates and contaminant conditions in nuclear plant systems and equipment.

3.1.6 Microbiologically Influenced Corrosion (MIC)

Microbiologically-influenced corrosion (MIC) is corrosive attack accelerated by the influence of microbiological activity and usually occurs at temperatures between 50 and 120F. Microbiological organisms disrupt the metal's protective oxide layer of the metal and produce corrosive substances and deposit solids that accelerate the electrolytic reactions of corrosive attack, generally in the form of pitting or crevice corrosion. The microbiological organisms can be either aerobic or anaerobic, depending on the available oxygen content. MIC is facilitated by stagnant conditions, fouling, internal crevices, contact with untreated water from a natural source, and contact with contaminated soils. MIC damage (due to contact with contaminated soils) to the exterior of components is covered in Appendix E.

MIC is generally not assumed to be an airborne contaminant. MIC, therefore, is only a potential problem where contamination from untreated water or soil may have introduced the bacteria. Air and gas systems are only affected where stagnant conditions and the pooling of an untreated aqueous solution provide an environment suitable for propagation of the mechanism.

3.1.7 Wear and Fretting

Wear can result from the movement of a material in relation to another material that can occur during the active functions of a component. Components in this category are not addressed by this tool (e.g., air compressor, pump or valve operations). Wear can also occur as a result of movement on the external surfaces of equipment. Any such external component wear is covered in Appendix E.

Fretting is caused by small amplitude vibratory motion (e.g., flow induced vibration [FIV]) which results in removal of material between two contacting surfaces [5]. With the exception of heat exchangers, other passive components in systems containing gas are not susceptible to this mechanism. Heat exchangers are evaluated separately.

General wear and fretting are, therefore, not applicable to the equipment covered by this Gas Tool.

3.1.8 Selective Leaching

Selective leaching is the removal of one element from a solid alloy by corrosion processes. The most common example is the selective removal of zinc in brass alloys (dezincification). Common yellow brass (30% zinc and 70% copper) is most susceptible to this mechanism. Lower zinc levels and the addition of 1% tin for example, significantly reduce the susceptibility of the material [5]. There are two general types of dezincification, uniform attack and localized plug attack. In both types of dezincification, the zinc ions stay in solution while the copper plates back onto the surface of the brass. Zinc can corrode slowly in pure water by the cathodic ion reduction of water into hydrogen gas and hydroxide ions [5]. For this reason, dezincification can proceed in the absence of oxygen. The rate of corrosion, however, is increased in the presence of oxygen. This process occurs in clean water with no additional contaminant required for initiation [5].

Gray cast iron can also display the effects of selective leaching particularly in relatively mild environments. This process initiates with selective leaching of the iron or steel matrix leaving the graphitic network. The graphite is cathodic to iron, providing an excellent galvanic cell. The iron is dissolved, leaving a porous mass consisting of graphite, voids, and rust. If the cast iron is in an environment that corrodes this metal rapidly (e.g., saltwater), uniform corrosion can occur with a rapid loss of material strength which can go undetected as the corrosion appears superficial [5].

Aluminum bronze can be subject to de-alloying similar to the dezincification of brass. Aluminum brasses are used where impingement attack in turbulent high velocity saline water is the fluid. These alloys form a tough corrosion resistant protective coating due to the buildup of aluminum oxide. Proper quench and temper treatments for some of the aluminum bronzes produces a tempered structure that is superior in corrosion resistance to the normal annealed structures. Unless they are inhibited by adding 0.02 to 0.10% As, aluminum brasses are susceptible to selective leaching.

3.2 Cracking

Service induced cracking (initiation and growth)of base metal or weld metal may result from one or more of the following aging mechanisms: hydrogen damage, stress-corrosion cracking, vibration and fatigue.

3.2.1 Hydrogen Damage

Hydrogen damage results from absorption of hydrogen into the metal. It includes the following degradation mechanisms:

- hydrogen blistering
- hydrogen embrittlement
- decarburization
- hydrogen attack

Hydrogen blistering occurs as a result of the diffusion of monatomic hydrogen into voids in a metal. The atomic hydrogen then combines to form molecular hydrogen which is unable to diffuse through the metal. The concentration and pressure of hydrogen gas in the void then increases with a resultant blistering of material. This mechanism is most prevalent in the petroleum industry where chemical reactions produce significant levels of atomic hydrogen [5]. It is not a concern for the components within the scope of this tool.

Hydrogen embrittlement is the degradation of material mechanical properties a result of absorption of monatomic hydrogen into the material. As in hydrogen blistering, embrittlement requires the presence of atomic hydrogen as a result of some chemical process. High strength steels are the most susceptible to hydrogen embrittlement with the greatest susceptibility occurring around 70^{o}F. The susceptibility decreases rapidly as the temperature varies above and below 70^{o}F [4,6]. Alloying steels with nickel or molybedenum reduces hydrogen embrittlement susceptibility [4,6]. The stainless and nickel base alloys are considered immune to hydrogen embrittlement in most cases [4]. At yield strengths of less than 120 ksi for carbon and low alloy steels, concern regarding hydrogen cracking is alleviated except when the material is temper embrittled [2]. Since the yield strength of most of the piping and components in air and gas system applications is on the order of 30 to 45 ksi, hydrogen embrittlement is considered not applicable to carbon and low alloy steels.

Decarburization, or the removal of carbon from steel, is produced by moist hydrogen at high temperatures. Decarburization is extremely slow below 1,000^{o}C [4], which is significantly above the temperatures to which nuclear plant components are subjected. Hydrogen attack refers to the interaction between hydrogen and a component of an alloy at high temperatures. An example is the disintegration of oxygen-containing copper in the presence of hydrogen [5]. As in decarburization, hydrogen attack is a high temperature process at temperatures well above those of nuclear plants

Raychem Cryofit couplings are particularly sensitive to hydrogen embrittlement when subjected to a hydrogen environment at high temperatures (pressurizer region). These couplings are made of a special alloy (50% titanium and 50% nickel) called Tinel. The failure of these couplings in a high temperature (~ 600^{o} F) and high hydrogen content in the pressurizer gas space was attributed to hydrogen embrittlement as documented in NRC Information Notice No. 91-87. No other information as to hydrogen limits or temperature limits is available. For the purposes of this tool, any Cryofit couplings should be considered susceptible to hydrogen embrittlement if connected to the pressurizer gas space. This includes the Post Accident Sampling System (PASS).

With the exception of Raychem Cryofit couplings, hydrogen damage is considered not applicable to the materials and environments expected to be encountered during application of this tool.

3.2.2 Stress Corrosion Cracking

Stress corrosion cracking is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material in order to occur. Intergranular attack is similar to stress corrosion cracking except that stress is not necessary for it to proceed. With the exception of PWR reactor coolant system materials, stress corrosion cracking is of concern for PWRs and BWRs in low alloy steels, austenitic and martensitic stainless steels, and nickel-base alloy components. Piping carbon steels are considered resistant to SCC when the yield strength is less than 100 ksi [13]. Since the yield strength of most piping is in the 30 - 45 ksi range, SCC is not considered applicable to piping carbon steels. The detailed evaluation and identification of operational and residual stresses are beyond the scope of this tool. It is assumed that the materials within the scope of this tool contain sufficient stresses to initiate SCC given an environment conducive to the progression of either SCC or IGA.

Intergranular Stress Corrosion Cracking (IGSCC) is a major concern in a BWR primary system environment. The combination of dissolved oxygen in BWR coolant and sensitized austenitic stainless steels, associated primary system components, piping and BWR vessel internals render BWRs extremely susceptible to this mechanism. Other factors affecting the susceptibility to this mechanism include crevices, cold work during material fabrication, flow velocity and exposure to sulfates or halogens. To assist in the control of IGSCC in the BWR primary system environment, BWRs typically add hydrogen to suppress the formation of the oxidizing radiolytic products [16]. As this gas tool is not intended for use in the BWR primary fluid environment, the unique susceptibility to IGSCC in this environment is not included within this tool logic.

Stainless Steel (Wrought and Cast)

SCC and IGA have occurred in stainless steel typically in water systems containing dissolved oxygen, sulfates, fluorides or chlorides. Although temperatures above 200^{o}F are typically required, SCC has been observed at lower temperatures [4]. The presence of oxidizers often has a pronounced effect on cracking tendencies. In fact, the presence of dissolved oxygen or other oxidizing species is critical to the cracking in all chloride solutions. If the oxygen is removed, cracking will only occur when chloride concentrations are very high [4].

For the gas atmospheres covered by this tool, a concern arises when moisture containing contaminants concentrate, resulting in an environment conducive to SCC/IGA. The contaminants affecting stainless steel include sea water, chloride solutions, hydrogen sulfide, and sodium hydroxide [5].

Nickel-Base Alloys

The nickel-based alloys that are typically used for nuclear applications include nickel-chromium-iron alloys such as Alloy 600 and Alloy 690. The applications are typically restricted to the reactor coolant system (e.g., reactor vessel CRDM nozzles), but may also be found in selected non-Class 1 components such as the Core Flood Tanks. Alloy 690 was shown in the laboratory to be resistant to SCC in primary environments. However, there have been reported cases of SCC in Alloy 600 [3].

Aluminum

Pure aluminum is not susceptible to SCC/IGA, however, aluminum alloys containing more than 12% zinc or more than 6% magnesium are very susceptible to cracking under mild corrosive environments [5]. Aluminum alloys are susceptible to SCC/IGA in air and water vapor environments as well as in corrosive environments containing chloride solutions and saltwater.

Copper Alloys

The best known example of stress corrosion cracking is probably the so called “season cracking” of brass, so called due to its similarity to the cracking of seasoned wood. Ammonia and ammonium compounds are the corrosive substances most often associated with SCC of copper alloys. Both oxygen and moisture are necessary for ammonia to be corrosive to copper alloys; carbon dioxide is also thought to contribute to the process [4,5]. Brass alloys containing 64% to 65% copper are extremely susceptible to SCC, with resistance to cracking increasing progressively as the content of copper increases [4].

Bronze and other copper alloys are considerably more resistant to stress corrosion cracking than the brass (copper-zinc alloys) [4]. An exception is aluminum bronze which has demonstrated a susceptibility to SCC in moist ammonia environments. For the purpose of this tool the bronzes, with the exception of aluminum bronze, are considered immune to stress-corrosion cracking.

3.2.3 Vibration

Loss of pressure boundary integrity from vibration is typically caused by high cycle fatigue and is manifested as cracking, loss of threaded connection integrity and other plug/fitting failures. Air and gas lines typically consist of small diameter piping and tubing which can be sensitive to such failures. Air conditioner refrigerant lines may also show susceptibility to vibration induced failure dependent on quality of original design. These failures can occur where piping and/or tubing is in close proximity to such equipment as diesel generators, air compressors, and air amplifiers. All components are susceptible to this type of failure and it can occur regardless of temperature and environment.

This Mechanical Tool, based on significant industry failure experience, includes the logic to address vibration induced pressure boundary degradation. Some plants have experienced high incidences of vibration induced failures while other plants have experienced relatively few such failures. Whether or not such failures are just repaired, or a root cause program is invoked will also impact the incidence of future failures. Many plants have taken the approach that vibration failures are "infantile" in nature and result from design/installation/maintenance practices and are not an effect of aging. Plant specific failure history must be evaluated when considering vibration failures. This tool logic accounts for the plant-to-plant variations in susceptibility to vibration induced failures.

3.2.4 Mechanical/Thermal Fatigue

Aging effects of mechanical and thermal fatigue will be evaluated separately in Appendix H.

3.3 Reduction of Fracture Toughness

The fracture toughness of wrought austenitic stainless steel, CASS, and nickel-base alloys are typically higher than carbon and low alloy steels. Aging mechanisms that may lead to reduction of fracture toughness include thermal embrittlement, radiation embrittlement, and hydrogen embrittlement. Hydrogen embrittlement is covered in Section 3.2.1 of this tool which discusses hydrogen damage. The susceptibility of the materials listed in Section 2.1 to reduction of fracture toughness is discussed below.

3.3.1 Thermal Aging

Thermal aging, sometimes referred to as thermal embrittlement, is a time and temperature dependent mechanism where microstructural changes lead to increased yield and tensile strength properties, decreased ductility, and degradation of toughness properties. Cast austenitic stainless steels and precipitation-hardenable stainless steels are the only materials currently known to be susceptible to thermal aging for PWR and BWR conditions.

Embrittlement of CASS is a concern for license renewal at temperatures of 250°C (482°F) or more [11]. However, the range of operating temperatures will not cause thermal aging of the materials covered by this tool (≤ 200°F) is not conducive to thermal aging.

3.3.2 Radiation Embrittlement

Neutron irradiation can result in a decrease in fracture toughness of metals, however, it requires a neutron fluence far exceeding the neutron exposures of the components and systems in the non-Class 1 category [3]. Therefore, radiation embrittlement is considered not applicable to the components with gas environments.

3.4 Distortion

Distortion may be caused by plastic deformation due to temperature-related phenomena (e.g., creep). In general, distortion is addressed by the design codes and is not considered an applicable aging effect. Creep is not a plausible aging mechanism since the high temperatures required for this mechanism to occur (generally at temperatures > 40% of the alloy melting point) are not observed in commercial nuclear plant systems [3].

3.5 Loss of Mechanical Closure Integrity

3.5.1 Stress Relaxation

Stress relaxation is a potential ARDM for bolts in PWRs and BWRs [3]. Since bolted connections will be addressed in Appendix F, stress relaxation is considered not applicable to the tools presented herein.

3.6 Summary of Potential Aging Effects

Table 3-1 contains a summary of the various aging mechanisms and effects considered during the development of this tool. Also included are the conditions necessary for these aging effects to be manifested and the various materials that are susceptible to these effects.

Table 3-1 Summary of Potential Aging Effects				
Materials	***Loss of Material***	***Cracking***	***Reduction of Fracture Toughness***	***Distortion***
Stainless Steels	Pitting Crevice Corrosion MIC	SCC See App. H for Fatigue	Not Applicable	Not Applicable
Carbon Steel	General Corrosion Pitting Crevice Corrosion Galvanic Corrosion MIC	See App. H for Fatigue	Not Applicable	Not Applicable
Cast Iron	General Corrosion Pitting Crevice Corrosion Galvanic Corrosion MIC Selective Leaching (Gray Cast Iron)	See App. H for Fatigue	Not Applicable	Not Applicable
Galvanized Steel	Pitting Crevice Corrosion Galvanic Corrosion MIC	See Appendix H for Fatigue	Not Applicable	Not Applicable
Copper Alloys	Pitting Crevice Corrosion Galvanic Corrosion MIC	SCC See App. H for Fatigue	Not Applicable	Not Applicable
Brass	Pitting Crevice Corrosion MIC Selective Leaching (Yellow Brass)	Not Applicable	Not Applicable	Not Applicable
Aluminum	Pitting Crevice Corrosion Galvanic Corrosion MIC Selective Leaching (Aluminum Bronze)	SCC (Aluminum Alloys > 12% Zinc or > 6% Magnesium See App. H for Fatigue	Not Applicable	Not Applicable
Alloy 600	Pitting Crevice Corrosion MIC	SCC See App. H for Fatigue	Not Applicable	Not Applicable
High Strength Specialty Alloys	Pitting Crevice Corrosion MIC	Hydrogen Damage (requires Hydrogen Ions and High Temperature) See App. H for Fatigue	Not Applicable	Not Applicable

3.7 Operating History

An operational history review was performed using NPRDS and a review of NRC generic communications that apply to air and gas systems. Each is reported separately below.

3.7.1 NPRDS Review

The Nuclear Plant Reliability Data System (NPRDS) contains information on plant operating experiences. The purpose of a review of this material is to assure that failures of in-scope equipment due to aging is considered and also to assure that overly conservative assessments of equipment aging are not made (e.g., assuming hydrogen damage of various equipment is plausible when plant operating data does not support that finding).

The Gas Tool encompasses numerous systems, environments and materials. As a result, it would be extremely time consuming to sort and review all NPRDS entries that cover this entire spectrum of combinations. The search criteria included all NPRDS reportable systems normally associated with a gas environment, as well as all area cooling systems for which failure data was available. There are several concerns and/or precautions regarding the use of this data; however, the informative nature of the data outweighs the recognized limitations.

For the NPRDS data base query, the following search conditions were selected:

- Selected Safety Classes are Safety-Related Components, Non Safety-Related Components, and Other
- Selected Failure Cause Categories are Age/Normal Usage, Unknown (included Code X prior to 4/94), and Other (was included in Code K prior to 4/94)
- Excluded Corrective Action is Recalibrate/Adjust
- Selected NSSSs are Babcock & Wilcox, Combustion Engineering, Westinghouse PWRs and General Electric BWRs.
- Selected Components are ACCUMU, FILTER, PIPE, PUMP, VALVE, and VESSEL
- Excluded PIPE Failure Mode is Plugged Pipe
- Excluded PUMP Failure Mode is Failed to Start
- Excluded VALVE Failure Modes are Failed to Close, Failed to Open, Internal Leakage, Fail to Operate Properly (Back-fit Only), Fail to Operate as Required, Premature Opening, and Fail to Remain Open

- Selected Failure/Cause Descriptions are Foreign Material/Substance (include AJ before 4/94), Particulate Contamination, Normal Wear (included AH before 4/94), Welding Process, Abnormal Stress (Mech.) (included AQ before 4/94), Abnormal Wear (included in AD before 4/94), Loose Parts (included AP before 4/94), Mechanical Damage (included BK before 4/94), Aging/Cyclic Fatigue(Mech.) (included BL before 4/94), Dirty, Corrosion, Mech. Binding/Sticking (included in BB before 4/94), Mechanical Interference (include in BF before 4/94), Environmental Condition (code added 4/94), and Other (code added 4/94)

- Selected Systems are Room/Area Cooling System-BW, Diesel Starting Air-BW, Penetration Room Ventilation-BW, Room/Area Cooling System-CE, Diesel Starting Air-CE, Containment Cooling-CE, Annulus Ventilation-CE, Penetration Room Ventilation-CE, Room/Area Cooling System-W, Diesel Starting Air-W, Containment Fan Cooling-W, Annulus Ventilation-W, Room Area Cooling-GE, Standby Gas Treatment-GE, Combustible Gas Control-Recombiner-GE, Combustible Gas Control-Dilution-GE, Containment Atmosphere cooling-GE, HPCS Power-Diesel Starting Air-GE and Diesel Starting Air-GE.

The purpose of the NPRDS search was to identify equipment failures resulting from the effects of aging. Although NPRDS searches of PWR and BWR data were conducted separately, the results are not reported separately in this gas tool. Both the included systems and the recorded failures for the various reactor types are very similar and separate discussions are not necessary. Using the above search criteria, 529 entries were selected. These records were reviewed and those involving consumables such as failed/worn gaskets, packing material failures, and other diaphragm, seal or sealant failures were excluded from further consideration. Other failures relating to design problems, failures resulting from faulty maintenance, clogged filters and other various failures not related to equipment aging were also excluded. Failures involving valve opening/closing and valve leakage concerns were also excluded as these types of failures for the Safety Related equipment are covered within the auspices of the Maintenance Rule.

A majority of the selected entries were excluded. Of the 529 items identified, 295 involved valve actuation, internals degradation/wear or valve leakage problems which are considered “active” failures and covered by the Maintenance Rule programs. Gasket, seal, sealant, diaphragm O-ring and other consumable related failures accounted for 118 of the entries; clogged filters or filters that failed performance testing programs represented 40 entries; miscellaneous failures involving mechanical and or electrical failures due to non-aging related concerns involved 32 entries.

There were 44 entries that represented equipment failures resulting from the effects of aging. Table 3-2 identifies the number of records attributable to the various aging mechanisms and includes a percentage of the total for each category.

Table 3-2 NPRDS Search Summary

FAILURE CAUSE	NO. OF ENTRIES	% OF TOTAL
Wear	4	9
Vibration	7	16
Structural Integrity Loss	23	52
Corrosion	8	18
Fatigue (thermal cycling)	1	2
Aging (non-metal)	1	2

Wear of components that resulted in reportable equipment failures had various causes including; external wear, flex line failure, and wear of threads on a pipe connection. The failure of an above seat spring on an air system valve was also included in this category. The vibration failures resulted from close proximity to either compressors or air regulators. These failures included pressure boundary failures rigid lines, flex-lines and threaded piping connections, as well as in one case the loosening of an air regulator cap.

Pressure boundary failures involved two distinct mechanisms: (1) corrosion mechanisms, and (2) failures attributable to mechanical breakage or deformation of pressure boundary components (classified as "Structural Integrity Loss" in the above table). The corrosion failures consisted of a variety of corrosive mechanisms and affected a diverse population of components and equipment. For the systems included in the search, failures due to corrosion were found to affect air system components, various duct material, and charcoal filter casings. One listing of a broken hand-wheel (listing identified corrosion as the cause of failure) on an air system valve was also included in this category.

The failures included in the loss of structural integrity category were very diverse. All pressure boundary losses that did not fall into the "valve leakage," or consumable category, and which did not list corrosion as the cause of failure, were grouped in this category. These listings included; air system leakage, body to bonnet leaks (where no consumable failure such as "O" ring or gasket was identified), filter casing leaks, valve body deformation, "O" ring seat erosion, bushing cracking/failures. Other failures included several cases of broken sight glasses on air system components, one filter canister rupture on an air system filter, two wire mesh failures on filter internals, the failure of a fin on an HVAC damper and one case of the failure of a rubber lining in a BWR standby gas system valve (the rubber failure resulted in flange leakage).

A majority of these loss of structural integrity failures could not be directly linked to specific degradation mechanisms and, for some, the after effects of the failure (e.g. erosion of O-ring seat) cannot necessarily be distinguished from the failure itself. It must also be noted that for a majority of these failures the system was still capable of performing its required functions (per the NPRDS report sheet). What is not clear is whether the failure involved equipment required to perform license renewal "intended" functions.

A fatigue failure to a compressor air line was attributable to excessive cycling of the compressor. The last failure identified (non-metal) resulted from aging of a rubber expansion boot joint in a ventilation system.

The following observations and limitations were noted during the review of the NPRDS entries.

1. It is often not clear as to the exact cause of failure due to the vagueness of the information available. Although previous maintenance in some cases may be suspect, it is seldom identified as a cause. Several cases of broken sight glasses on air system equipment may be the result of unintentional damage during either inspections or repair activities, although aging of the glass cannot be unequivocally excluded from consideration.

2. Due to the relative low cost of replacement of items in the air systems, the cause of failure is often not evaluated as the items are replaced rather than repaired.

3. As the mechanics are not always well versed in aging and corrosion mechanisms, the identified causes may not always be accurate. For example, rusting was listed as the cause of failure of what was identified as "aluminum duct".

4. It is not always clear for the listings evaluated here whether failures due to corrosion or wear mechanisms were initiated internally or externally to the component. Only those failures originating internally to a component are covered by this tool.

5. Many pressure boundary failures due to aging of consumables such as "O" rings, gaskets, sealants, and diaphragms were revealed. This data does indicate that, for the most part, the failures did <u>not</u> result in a loss of the system functions.

6. Many failures of air system components resulted from dirty or contaminated air supplies, which resulted in oil, moisture, and sludge buildup.

7. Vibration induced failures are often not identified as such. However, in many cases failures were apparent on equipment in very close proximity to air compressors and other vibrating equipment. Numerous listings of threaded connections were identified in air compressor discharge lines.

3.7.2 Applicable NRC Generic Correspondence

A search was made of generic NRC correspondence that might relate to aging degradation in air and gas mechanical pressure boundary components. Gas systems typically include instrument air, compressed air, nitrogen, hydrogen, carbon dioxide, off-gas systems and standby gas treatment systems. In addition to air systems, other components that use or contain air and gas products include various fluid tanks, air ducts in various air cooling systems, and air sampling systems to name a few. These systems are constructed from carbon steel, stainless steel, brass, bronze, aluminum, cast aluminum, and galvanized steel and other non metallic materials. The NRC generic correspondence searched included Circulars, Bulletins, Information Notices, and Generic Letters. Eight entries were found to be related, either directly or indirectly, to air and gas system failures. Not all involved age related degradation phenomenon, however, each identified entry has been cited and discussed below.

Circulars
No circulars were identified that relate to aging concerns in air or gas systems.

Information Notices

IN 80-40: Excessive Nitrogen Supply Pressure Actuates Safety-Relief Valve Operation to Cause Reactor De-pressurization.
The excessive nitrogen supply pressure was due to addition of new supply of liquid nitrogen to the storage tanks. Nitrogen pressure supplying the safety-relief valves increased to 160-165 psi. This may have been caused by liquid nitrogen reaching the pressure regulators or by a failure in a pressure regulator - active components. Therefore, there are no license renewal issues within this Information Notice.

IN 81-38: Potentially Significant Equipment Failures Resulting From Contamination of Air-Operated Systems.
Air operated components and systems will occasionally become inoperable because they are contaminated with oil, water, desiccant, rust or other corrosion products. Problem of air system contamination potentially pose a common mode failure condition. This information notice provides several recommendations to minimize air system contamination problem, therefore reducing the probability of air operated component failures. All recommendations are good maintenance practice items.

IN 84-17: Problems with Liquid Nitrogen Cooling Components Below the NIL Ductility Temperature.
Nitrogen is used at some sites for inerting the containment atmosphere during power operation. The nitrogen is admitted to the containment after it is evaporated and warmed from its liquid form. There are several controls in place to prevent liquid nitrogen to come in contact with components such as pipes.

Circumferential cracks were observed on piping which was due to brittle fracture caused by the piping temperature to have been below its nil ductility temperature. Failure of nitrogen evaporator and isolation valves controls were the root cause of liquid nitrogen coming in contact with plant piping and plant components. No aging issues are present in this generic communication.

IN 85-99: Cracking in Boiling Water Reactor Mark I and Mark II Containments Caused by Failure of the Inerting System.
This information notice is a follow up to IN 84-17 and advises of the discovery of another crack in a drywell vent header which occurred during inerting system operation. The failure was attributed to brittle fracture caused by the injection of cold nitrogen during inerting. This failure is a design and system operation concern and is not the result of component aging.

IN 87-28, REV 0 and Suppl. 1: Air Systems Problems at U.S. Light Water Reactors.
This information notice and its supplement provides recipients a copy of NUREG-1275, Vol II, "Operating Experience Feedback Report - Air Systems Problems."

Air system failures may cause significant damage to plant safety systems. The root causes of most of the failures were traceable to design and or maintenance deficiencies. The design and operating problems appear to reflect a lack of adequate attention to design, maintenance, operation, and administrative control of air systems. No aging issues are present in this generic communication.

IN 91-87: Hydrogen Embrittlement of Raychem Cryofit Couplings
Failure of Cryofit coupling manufactured by Raychem due to hydrogen embrittlement. All couplings of this type has been replaced at one site. Raychem Cryofit couplings are made of a special alloy (50 percent titanium and 50 percent nickel) called Tinel that expands as temperature is decreased and contracts as temperature increases.

The cause of coupling failure was determined to be hydrogen embrittlement of Tinel. The high hydrogen content in the exposure medium and high temperature was the critical determining factor, no other combination of exposure environments resulted in degradation of the Tinel.

IN 92-32: Problems Identified With Emergency Ventilation Systems for Near-Site (Within 10 Miles) Emergency Operations Facilities and Technical Support Centers
This information notice alerted licensees to potential problems resulting from inadequate maintenance and testing of Emergency Operations Facility (EOF) and Technical Support Center (TSC) emergency ventilation systems. These problems could result in a situation after an accident in which the EOF or TSC would not provide the level of protection to emergency workers that was intended. It is was suggested that licensees review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. This IN focused on inadequate maintenance and testing, and no specific aging effects were discussed.

IN 93-06: Potential Bypass Leakage Paths Around Filters Installed in Ventilation Systems
This information notice alerted licensees to potential problems resulting from missing or deteriorated seals around shafts that penetrate fan or filter housings and inadequately sealed ducting seams used in engineered safety feature (ESF)ventilation systems. As discussed in Section 2.2 of the Implementation Guide, seals are not subject to aging management review.

IE Bulletins

IE Bulletin 84-01: Cracks in Boiling Water Reactor Mark 1 Containment Vent Headers.
This IE Bulletin was written to address the same concerns as those previously discussed in IN 84-17 and IN 85-99. The cracks in the vent headers have been attributed to improper operation of the inerting system. No aging concerns are applicable.

Generic Letters
GL 88-14: Instrument Air Supply System Problems Affecting Safety-Related Equipment
Inadequacies in design, installation, and maintenance of instrument air systems have resulted in failures which adversely affect safety-related equipment. In addition, anticipated transients and system recovery procedures are frequently inadequate and the operators are not well trained for coping with loss of instrument air conditions.

The purpose of this generic letter is to request that each licensee review NUREG-1275, Vol. 2, and perform a design and operations verification of the instrument air systems. There are no license renewal issues associated with this generic letter.

3.7.3 Summary of Industry Document Search

The Industry Document Search consisted of a review of NRC correspondence which included: Circulars, Information Notices, IE Bulletins, and Generic Letters. Of the eight industry documents identified as potential aging concerns for air and gas systems, four identified concerns with operation, design, installation or maintenance of nitrogen addition systems. Three industry documents involved the failure of instrument air systems due to inadequate design, installation, maintenance or operation of the system or its components. Although air or gas system contamination from these inadequacies can cause or hasten the onset of pressure boundary degradation, aging degradation is not the issue addressed in these industry correspondences. The tool logic, however, does provide for consideration of contamination and the subsequent aging effects resulting from air system contamination.

Only one industry document involved age related degradation of air or gas system equipment. Information Notice 91-82 concerns the failure of Cryofit couplings manufactured by Raychem as a result of hydrogen embrittlement. This aging concern is specifically addressed in this gas tool logic.

4. FLOW DIAGRAM DEVELOPMENT

4.1 Assumptions

The assumptions used to develop the evaluation flow chart are provided below.

1. The gas sources (hydrogen, nitrogen, carbon dioxide, fluorocarbons) evaluated as internal environments for this tool are clean dry sources with no significant levels of contaminants such as chlorides, sulfates, or oxygen. The exception is when replacement gases for freon have been used. Some of these gases are corrosive. The flow chart evaluates the applications where freon substitutes have been used.

2. Nonmetallic materials such as plastic, rubber, and other “consumable” items (gaskets, O-rings, seals, and sealing compounds) are not covered.

3. Crevice corrosion requires some type of crevice (an opening usually a few thousandths or an inch or less in width) to occur. It is unreasonable to expect an evaluator to respond to a question of whether or not a crevice exists within a system or component. The logic, therefore, will assume conservatively that the potential exists for crevices in all components and systems.

4. Some aging effects are the result of mechanisms that require the material to be under stresses which would be difficult to predict. It would be unreasonable to expect an evaluator to establish the presence of stresses resulting from the manufacturing process or post-installation welding for every component under consideration. In these cases, the logic will conservatively assume that the stress exists.

5. Macroorganisms are assumed not to be present to any significant degree for the purposes of this tool. Macroorganisms are only present in raw water systems. The appropriate raw water system tool is assumed to evaluate these effects where appropriate.

6. Oxygen level is a significant parameter in many aging mechanisms. This tool assumes that the level of oxygen in the atmosphere is at least above the threshold value to cause corrosive effects.

7. Aggressive chemical species include, but are not limited to, oxygen, halides and sulfates. These aggressive species significantly influence the nature, rate, and severity of corrosion. It is generally assumed that atmospheric environments include air borne contaminants and, for the purposes of this tool, it is assumed that these contaminants are present in all but the purest of gasses. It is also assumed that these contaminants are not at a sufficient level to result in significant corrosion rates in gas environments unless they are concentrated as a result of cyclic (wet-dry) condensation, accidental contamination, or chronic leakage.

8. Oil may be present in some air supply systems. Oil is not a good electrolyte and without other contaminants does not create a corrosive environment [5, 10]. It is assumed for the purposes of this tool that oil contamination does not result in any degradation effects over and above those that would occur without the presence of oil contamination. The one exception is the potential for oil contamination to provide a source of microorganisms to the gas system. Microorganisms have been found in oil, especially where the oil quality is not maintained and/or the source of the oil is from a reservoir or tank that may be contaminated.

4.2 General

The Mechanical Tools being developed are intended to provide an efficient method to identify applicable aging effects for systems and components which are required to undergo an aging management review in compliance with the license renewal rule. Implementation of these tools at the various sites will result in the identification of plant equipment and aging effects which must be managed or justified not to be managed during the renewal period. Demonstration of the adequacy of aging management programs to manage these effects is outside the scope of this tool and will be addressed separately.

These tools will identify potential aging effects and also direct the user to areas in the system where these effects might be preferentially manifested. The discussions in Section 3 identified numerous aging mechanisms and their associated aging "effects" which potentially can occur in the gas system equipment addressed by these tools. This logic tool, Figure 1, then guides the user through logic to determine, based on specific system or component materials, environment and/or operating conditions, whether these effects are applicable. The tool described in the following sections address the "effects" of aging on various materials when subjected to gas environments. The tool is organized such that the individuals utilizing the tool do not require detailed knowledge of aging mechanisms or their effects. The logic does, however, require that the user is familiar with the materials of construction, various applicable environments, and all system operating conditions.

The evaluation logic groups aging effects such as loss of material and cracking to efficiently resolve the disposition of equipment. Implementation of the tool, in effect, documents the resolution of aging mechanisms, the resultant aging effects, and provides a link to the program evaluations and Aging Management Review (AMR) phase. The results not only identify the effects which must be managed but, given the screening criteria, can be a valuable input when determining how and where to implement aging management programs.

4.3 Tool Description

Figure 1 contains the logic and criteria to evaluate aging effects for various materials in an air or gas environment. The materials and gasses covered by this tool are described in detail in Sections 2.0 of this tool.

The upper branch of the tool is intended to cover a very specific issue that resulted from the NRC document search. Specifically the issue is hydrogen embrittlement of Raychem Cryofit Couplings in the pressurizer gas space sample line. This issue represents the only indication of hydrogen damage uncovered during the document search. A review of information included in the referenced corrosion handbooks and other available information indicates that likelihood of hydrogen damage to material at nuclear plants is extremely low. Therefore, with the exception of the Raychem Cryofit Couplings, hydrogen damage is assumed not to occur. It is included in this tool to address the very specific issue covered by NRC Information Notice 91-87.

Since moisture or fluid is necessary for the propagation of the remaining degradation mechanisms, the next tier of the logic provides for the exclusion of all “dry” gas environments. Components that are subjected only to processed gasses that contain little if any moisture are not likely to realize any significant degradation mechanisms regardless of the material. Environments meeting this criteria include dried/filtered air, clean processed nitrogen, carbon dioxide and hydrogen. HVAC and other air supply systems contain air with varying degrees of moisture content that, for the most part, will not result in an aggressive environment. Unless situations produce a “wetted” environment in these air systems the logic provides for the conclusion that, with the exception of general corrosion of cast iron or carbon steel, there are no aging effects. An example of a situation in which pooled water can occur in air HVAC systems is immediately downstream of a cooler. In cases of extreme condensation on cooler tubes, moisture carryover of entrained particles can occur with subsequent pooling immediately downstream of the coolers. This pooling produces a wetted environment where corrosion of carbon steel or cast iron material can occur.

The next two logic provisions involve mechanisms that can occur under atmospheric moisture conditions. Although system and component design should preclude the occurrence of galvanic corrosion, it can be a significant aging mechanism as the results are sometimes hard to detect prior to pressure boundary failure. Due to the variety of materials covered by this tool, galvanic corrosion is a concern in the air and gas systems.

General corrosion is another degradation mechanism that can occur under atmospheric moisture conditions, however, of the materials included in this tool, only carbon steel and cast iron are susceptible. A means to prevent general corrosion of carbon steel or cast iron is to either paint or coat the material to provide a moisture barrier. In conjunction with a program to maintain or inspect the painted or coated surfaces, general corrosion is not a concern for these surfaces.

The remainder of the degradation mechanisms included in the tool logic require a wetted surface or pooled liquid environment. Under these conditions all materials can be subject to crevice and pitting corrosion in the presence of a contaminant such as chloride or sulfide. In the presence of a contaminant, stainless steel, brass, Alloy 600, and aluminum alloys (aluminum in its pure form is not susceptible) are susceptible to stress-corrosion cracking.

Selective leaching in a wetted environment can occur with no other contaminants present. The logic tree addresses this issue by singling out yellow brass and gray cast iron as the materials susceptible to this loss of material effect. (Selective leaching is commonly referred to as dezincification and graphitization for these two metals respectively). Aluminum bronze is susceptible to a mechanism similar to dezincification and is also included in this category.

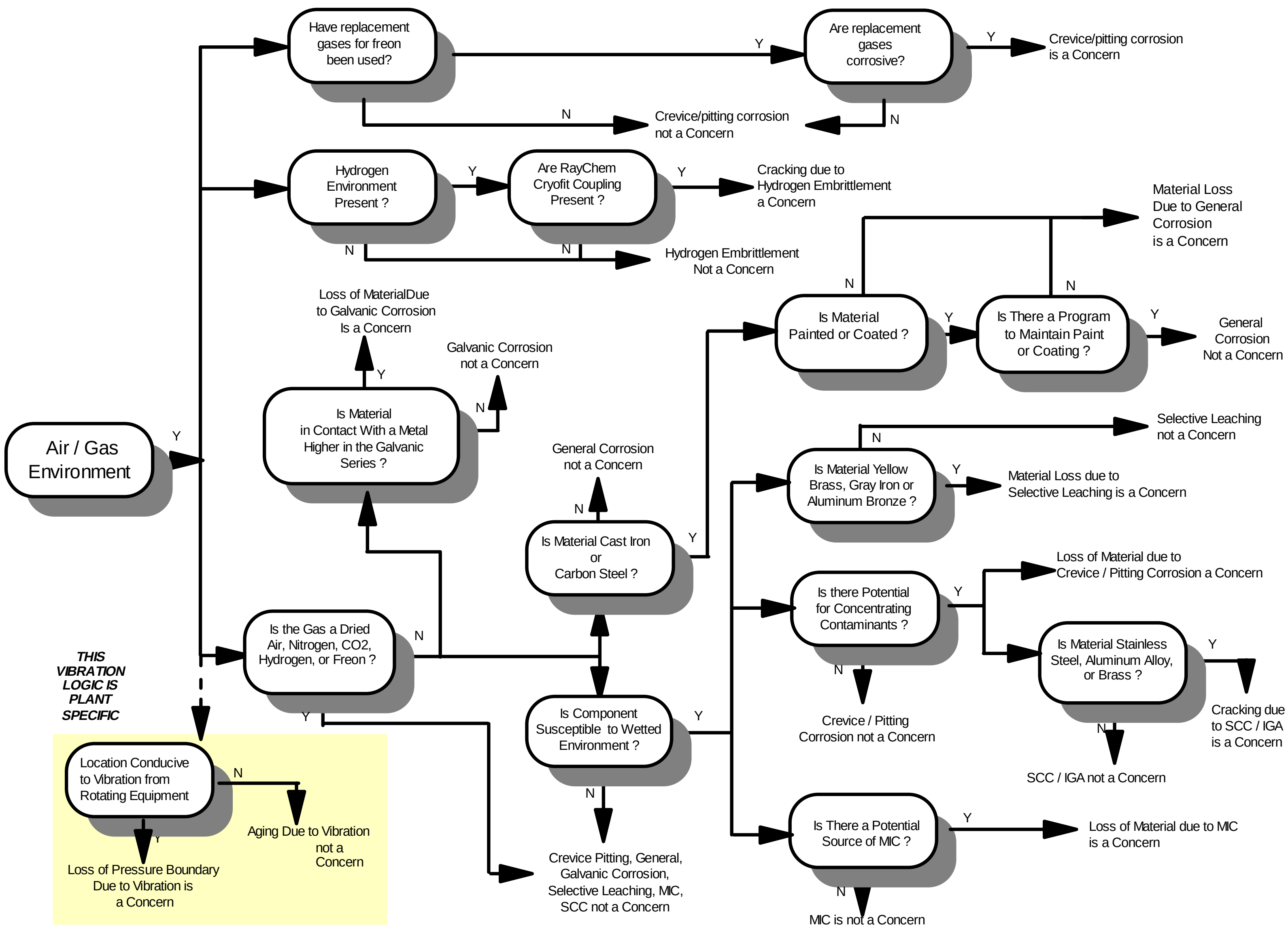
The last leg on the logic diagram addresses Microbiologically Induced Corrosion (MIC). MIC is not an airborne contaminant, therefore, a source of the microbe would have to be introduced into an air gas environment for MIC to be of concern. Microorganisms can be introduced into a gas environment from many sources. Some air spaces within the scope of this tool are in raw water systems which may contain the microbes. Fire protection systems may also have air spaces and use raw water as a source of water. Another source of microbe introduction can be from contamination or leakage from a raw water source. As an example, leakage from a raw water chiller or cooler into an air system could result in the introduction of MIC. The leakage may also provide for the wetted environment necessary for the progression of this effect. Contaminated oil if used in air systems can also provide for the introduction of these microorganisms.

4.3.1 Optional Vibration Consideration

As discussed in Section 3.2.3, the chosen approach to address the loss of pressure boundary integrity resulting from vibration is a plant specific issue. Some plants will take the position that vibration induced failures typically occur early in plant life and are a design/installation/maintenance issue rather than an aging effect. Other plants will include vibration induced failures as an aging effect based on either plant specific or industry wide failure history. The shaded portion of this Gas Tool logic is included as an “option” to allow each utility to address vibration in a way that best fits into their specific aging management program approach.

The logic is very simplistic in that it focuses attention on components and piping which are in close proximity to rotating or vibrating equipment. No specific proximity distances are identified as these will vary based on the type of equipment and the material used.

Figure 1 Air/Gas Tool



5. CERTIFICATION

This appendix is an accurate description of aging effects of various materials in a gas environment prepared for the B&W Owners Group Generic License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

D J Firth 8/14/99

David J. Firth Date
GLRP Project Manager

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Appendix E
External Surfaces

The External Surfaces Tool provides a methodology for identifying the aging effects of external surfaces of mechanical components manufactured from carbon and low alloy steel and stainless steel. The other Mechanical Tools focus on a specific material and a particular environment (e.g., stainless steel in a treated water environment). For the other tools, the environment analyzed was for the internal flowing fluid. The bases and supporting documentation for the external surfaces of carbon and stainless steels are discussed and developed in this document.

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1. INTRODUCTION

The External Surfaces Tool provides a methodology to identify applicable aging effects of the external surfaces of non-Class 1 carbon and stainless steel mechanical components. Appendices A through D evaluate aging effects for the internal fluid surfaces for specific materials and environments (e.g., stainless steel in a borated water environment). This external surface tool considers aging effects resulting from exposure to the diverse external environments of carbon and stainless steel surfaces. The external surfaces of carbon steel material are often painted or coated and, therefore, these surface treatments are considered in the tool logic. Because galvanized steel is widely used for outdoor exposure, a detailed discussion of specific aging effects for galvanized steel is included both in the discussions and in the tool logic. Since the other tools only analyzed flowing fluid environments, there is a need for a tool that addresses aging of the external surfaces. There is therefore a need for a tool to enable the aging evaluation of the external surfaces not seeing the flowing process fluid. The bases and supporting documentation for the external surfaces of carbon and stainless steels are developed in this document.

Applicable aging effects include cracking, loss of material, reduction of fracture toughness, distortion, and loss of mechanical closure integrity. The External Surfaces Tool may be applied to all mechanical components within the License Renewal Scope except bolted closures. These components are treated separately in Appendix F. In addition, cracking by fatigue should be addressed using the Fatigue Tool in Appendix H.

This Mechanical Tool focuses on the external surfaces of mechanical fluid system components (piping, pumps, valves, fittings, etc.). However, the aging effects would be applicable for a similar material/environment combination provided that all assumptions and considerations discussed herein are verified for the particular application.

2. MATERIAL AND ENVIRONMENT

This tool provides the logic and methodology to identify the applicable aging effects of external surfaces of carbon steel and stainless steel components. Many of the in-scope components are either coated or painted to minimize exterior surface degradation and consideration is included in the tool logic for such protection. Because galvanized carbon steel is widely used for outdoor exposure, and its potential impact (under certain conditions) on the base carbon steel material, specific aging effects for galvanized steel are included in the logic.

The majority of surfaces covered by this tool are exposed to either indoor or outdoor atmospheric conditions. These environments include various levels of humidity, rain water, condensation, and air-borne contaminants such as sulfur dioxide, chlorine gases, sulfur gases, and ozone, etc. Depending on the specific equipment location and operating conditions, frequent wetting or alternate wetting/drying can occur. All outdoor equipment is probably exposed to alternate wetting/drying, however, even enclosed or covered equipment can be exposed to intermittent or frequent condensation and/or leakage. Buried components exposed to a wetted soil environment can have unique aging effects and this environment is also considered in this tool. The impact of concrete on the aging effects of embedded mechanical equipment is also included. Since other equipment (particulary components or piping in the vicinity of the intake structure) may be submerged in raw water, the user is referred to Appendix B of these tools for the aging effects evaluation. There are also equipment submerged in treat water (e.g., piping in the suppression chamber). These components should be evaluated using the methods of Appendix A.

The term carbon steel as used in the aging evaluation applies to all carbon and low-alloy steels. The term stainless steel focuses primarily on Types 304 and 316 stainless steels. In order to respond to some of the logic questions, it may be necessary to know if the carbon content is low, e.g., Type 304L or Type 316L. Additional discussion of stainless steels and weld material can be found in Appendix A.

3. AGING EFFECTS

This document addresses the aging effects resulting from a variety of aging mechanisms. Where specific mechanisms are not applicable under the environmental and material conditions covered by the tool, reasoning is provided for a “not applicable” determination. For those mechanisms that are applicable for the equipment covered by this tool, a discussion of the conditions necessary for the mechanism is included.

3.1 Loss of Material

3.1.1 General Corrosion

General corrosion is the result of a chemical or electrochemical reaction between a material and an aggressive environment. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup [2]. At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are the primary factors for the corrosion of iron. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any practical extent [3]. Carbon and low-alloy steels are susceptible to general corrosion whereas austenitic stainless steels are resistant to general corrosion [5].

The austenitic Cr-Ni steels of the 18-8 type (18%Cr, 8%Ni) are resistant to corrosion in atmospheric conditions both for interior and exterior exposures and under conditions of high or low humidity. The stainless steels are resistant to the action of water and in most environments show no signs of permanent staining even after long exposure [3].

Approximate compositions of Type 304 and Type 316 stainless steel [11] are shown below.

	%C	%Mn	%Si	%Cr	%Ni	%Mo
Type 304	0.08	2.0	1.0	18-20	8-10.5	....
Type 316	0.08	2.0	1.0	16-18	10-14	2-3.0

There is much test data on atmospheric corrosion of stainless steel reported in Ref. [6]. Most of this data shows that about 12% chromium for industrial and rural areas and about 15% chromium for marine atmospheres is sufficient to provide negligible corrosion effects. As identified above, both 304 and 316 stainless steels contain chromium at levels sufficient to provide excellent resistance to corrosion in both industrial and marine environments. Type 316 is more resistant than type 304 to general corrosion and pitting due to the higher nickel and molybdenum content [6].

A significant effort has been expended by corrosion researchers to understand the factors that influence outdoor marine and urban atmospheric corrosion. Relative humidity, temperature, sulfur dioxide, and chloride concentrations are among the more important variables. Outdoor atmospheric parameters can be significantly altered inside buildings and the work in Ref. [6] and others assume the indoor level of pollutants is a certain percentage of the outdoor level. Tests show that metals do corrode indoors, however, the corrosion rate increases rapidly when exposed to an outdoor environment.

Atmospheres can be classified as industrial, marine, or rural. Corrosion is caused by moisture and oxygen but is accelerated by contaminates such as sulfur compounds and sodium chloride. Corrosion of carbon steel on the seacoast is 400 to 500 times greater than in the desert area. Steel specimens 80 feet from the shoreline corroded 12 times faster than those 800 feet away. Sodium chloride is the primary contaminant of concern. Industrial atmospheres can be 50 to 100 times more corrosive than desert areas [6]. Locations where moisture condenses or accumulates and does not dry out for long periods of time can cause damage sometimes referred to as sheltered corrosion [6]. For the purposes of this logic tool, the rate of general corrosion will not be evaluated. That is, if the conditions exist such that the mechanism is plausible, it will be a concern regardless of the rate of corrosion.

The factors affecting corrosiveness of soils are moisture, pH (alkalinity or acidity), permeability of water, and air (compactness or texture), oxygen, salts, stray currents, and biological organisms. Most of these affect electrical resistance, which is a good measure of corrosion potential. High-resistance dry soils are generally not very corrosive. Carbon steel and cast iron with and without organic coatings and cathodic protection are most common for underground components as other materials are generally not economical [5]. For the purposes of this logic tool, buried components are assumed to be susceptible to corrosion because of the potential for oxygen levels, moisture content, biological organisms, and contaminates unless otherwise protected by monitored programs. Multi-layered coatings and cathodic protection programs should be credited and evaluated on a plant-specific basis.

The high alkalinity of concrete ($pH > 12.5$) provides an environment that protects embedded steel from corrosion. However, when the pH is reduced ($pH < 11.5$) by the intrusion of aggressive ions [e.g., chlorides > 500 ppm], corrosion can occur. A reduced pH could be caused by leaching of alkaline products through cracks, entry of acidic materials, carbonation, contaminated concrete mix, or moisture intrusion [1,15].

Some materials under consideration will be subjected to a completely submerged environment. These conditions are commonplace in intake structures and piping entering the plant from the raw water sources. Although not completely submerged, some equipment is located in what is called a “splash zone.” This location is typically adjacent to a raw water source such as a lake or ocean where either a continuous wetting or “splashing” of a component due to wind, surf, waves, etc. provides an environment not unlike that of a fully submerged component. Equipment in this “splash zone” should be considered submerged when evaluating for applicable aging effects. effects. The environment for submerged or continuously wetted equipment is classified as a raw water environment and for the identification of applicable aging effects, the user is referred to the raw water tool contained in Appendix B of these Mechanical Tools. The raw water tool includes consideration of macroorganisms, silt and other corrosion product buildup on the exterior surfaces of submerged equipment that can result in accelerated pitting and crevice corrosion rates at these locations.

3.1.2 Galvanic Corrosion

Galvanic corrosion occurs when materials with different electrochemical potentials are in contact in the presence of a corrosive environment [5].

Generally the effects of galvanic corrosion should be precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). Carbon and low-alloy steels have lower potentials than stainless steels and would be preferentially attacked in a galvanic couple. The rate of galvanic corrosion is governed by the relative size of the anode to cathode. The material with the lower potential (higher on galvanic series) is the anode and it sacrifices to the cathode. If the anode is appreciably larger than the cathode, then the galvanic corrosion rate is slow. Conversely, if the anode is much smaller than the cathode, then the galvanic corrosion rate can be very fast in the presence of moisture and water. Particular attention should be paid to component replacements and to carbon or low-alloy steel system interfaces with stainless steel systems.

Galvanic corrosion can occur in the atmosphere, the severity of which depends largely on the type and amount of moisture present. A saltwater environment is more corrosive than a rural atmosphere, therefore, galvanic corrosion will be greater near the seashore than in a dry rural area. Galvanic corrosion does not occur when the metals are completely dry since there is no electrolyte to electrically couple the two materials [3].

3.1.3 Crevice Corrosion

Crevice corrosion occurs when a crevice exists in a component that allows a corrosive environment to develop within the crevice. It occurs most frequently in joints and connections, or points of contact between metals and nonmetals, such as gasket surfaces, lap joints, and under bolt heads [5]. The nature of crevices, especially for those very small in size, is such that low flow or stagnant conditions can exist n the crevice regions even under system flowing conditions. Crevice corrosion is strongly dependent on the presence of dissolved oxygen. Although oxygen depletion in crevices may occur as a result of the corrosion process, oxygen is still required for the onset of corrosion, and bulk fluid oxygen content is necessary for the continued dissolution of material in the crevice [7]. For systems with extremely low oxygen content (<0.1 ppm.), crevice corrosion is considered to be insignificant [7]. Any fluids in contact with external surfaces will be exposed to atmospheric conditions and therefore saturated in oxygen above the threshold value of 0.1 ppm.

Carbon steels, low-alloy steels, stainless steels, and nickel-base alloys are all susceptible to crevice corrosion to some degree [3,5]. This form of corrosion as the name implies requires a crevice where contaminates and corrosion products can concentrate. In addition to oxygen, moisture is required for the mechanism to operate [3, 5]. Alternate wetting/drying is particularly harmful as this leads to a concentration of atmospheric pollutants and contaminants. In summary, crevice corrosion is a potential aging mechanism for wetted carbon and stainless steel.

3.1.4 Pitting Corrosion

Pitting corrosion is a corrosion mechanism that is more common with passive materials such as austenitic stainless steels than with non-passive materials, however, all materials of interest are susceptible to pitting corrosion under certain conditions. Unless cupric, ferric or mercuric halides are present in the environment, oxygen is required for pitting initiation. Areas where aggressive species can concentrate are particularly susceptible to pitting. Most pitting is the result of halide contamination, with chlorides, bromides, and hypochlorites being prevalent [5]. On the exterior surfaces of the mechanical equipment addressed by this tool, pitting is a significant aging effect for carbon and stainless steels when exposed to a corrosive environment.

Any continuously wetted or alternately wetted/dried surfaces tend to concentrate aggressive species and are prone to pitting corrosion. Environments that are conducive to pitting include, but are not limited to: 1) outdoor equipment exposed to the environment, 2) equipment exposed to frequent leakage, condensation or maintenance activities involving other equipment, 3) equipment located in the "splash" zone, 4) insulated equipment subject to sweating, and 5) piping where condensation is normal due to the flowing fluid temperature. Embedded equipment can be susceptible to pitting corrosion, especially where the material in contact with the metal contains aggressive chemicals. If not sealed properly, any gap between the metal and embedded material provides a location conducive to alternate wetting/drying, particularly if exposed to the outdoor environment.

Pitting corrosion can be inhibited by maintaining an adequate flow rate, however, continuous high flow rates on the exterior surfaces of mechanical equipment is not likely and is not evaluated within this tool. As indicated previously, submerged equipment should be evaluated using the raw water tool (Appendix B of these Mechanical Tools). The raw water tool considers the impact of fluid velocity as relates to pitting corrosion.

3.1.5 Erosion-Corrosion

Erosion-corrosion is a mechanism wherein fluid flow erodes or dissolves away the protective oxide or passive film of the metal, causing corrosion and re-oxidation. For external surfaces, this mechanism is only a concern for submerged equipment. Submerged equipment will be addressed using the raw water tool (Appendix B of these Mechanical Tools) which considers the effects of erosion-corrosion.

3.1.6 Microbiologically Influenced Corrosion (MIC)

Microbiologically influenced corrosion (MIC) is corrosive attack accelerated by the influence of microbiological activity. Although the bacteria can survive between -10 and 212^{o}F, this corrosion mechanism typically occurs at temperatures between 50 and 120^{o}F [12]. Microbiological organisms disrupt the protective oxide layer and produce corrosive substances and deposit solids that accelerate the electrolytic reactions of corrosive attack, generally in the form of pitting or crevice corrosion. This aging mechanism is facilitated by stagnant conditions, fouling, internal crevices, contact with untreated water from a natural source, and contact with contaminated soils. Nearly all materials of interest can be affected. In austenitic stainless steels MIC is almost always confined to welds and weld heat affected zones (HAZ). MIC in carbon and low-alloy steels is usually not isolated to particular locations as in stainless steels [9,10]. For the purposes of this external surface tool, any wetted areas (with the exception of exposure only to humidity) should be considered potential MIC susceptible locations.

3.1.7 Wear and Fretting

The only wear applicable to the external portions of equipment is the result of relative motion between components and/or piping. Fretting is the loss of material which occurs as a result of relative motion between two materials. A repeated removal of the normal corrosion product surface film and subsequent development of a new film results in a process similar to erosion/corrosion except under non-flowing conditions. Examples of fretting corrosion are repeated small displacements between piping and supports as a result of either thermal cycling or vibration. The result of wear and/or fretting aging mechanism is localized loss of material at the equipment/piping interface.

3.1.8 Macroorganisms

Aqueous macroorganisms such as barnacles, mussels, clams, algae and others are applicable only to submerged equipment or other components located in the "splash zone" of a raw water source. All such equipment should be evaluated using the raw water tool (Appendix B of these Mechanical Tools).

3.2 Cracking

3.2.1 Hydrogen Damage

Hydrogen damage results from the absorption of hydrogen into the metal. It includes the degradation mechanisms of hydrogen blistering and embrittlement [2,5]. Hydrogen blistering occurs primarily in low strength carbon and low-alloy steels in the temperature range of 30-300F [8]. Corrosion and the application of cathodic protection, electroplating, and other processes are major sources of hydrogen in metals [5]. Another term for hydrogen embrittlement is sulfide stress cracking if the cracking is caused by the presence of hydrogen sulfide. A few ppm of absorbed hydrogen can cause cracking [5].

Hydrogen blistering is most prevalent in the petroleum industry occurring in storage tanks and in refining processes [5]. A review of the failure data for PWR systems shows no evidence of hydrogen blistering for carbon steels, therefore, it is considered not applicable for carbon steels in nuclear power plant applications.

At yield strengths of less than 120 ksi for carbon and low-alloy steels, concern over hydrogen cracking is alleviated except when the material is temper embrittled [2]. Since the yield strength of most of the piping and components in nuclear power plant applications is on the order of 30 to

45 ksi, hydrogen embrittlement is considered not applicable to the external surfaces of carbon steels in the nuclear power plant applications.

In most cases, austenitic stainless steels are immune to hydrogen damage although nickel-base alloys may be somewhat susceptible [2,3]. Therefore, hydrogen damage is considered not applicable to the external surfaces of stainless steels.

3.2.2 Stress Corrosion Cracking/Intergranular Attack

Stress corrosion cracking is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material in order to occur. Intergranular attack is similar to stress corrosion cracking except that stress is not necessary for it to proceed. In the case of SCC of carbon and low-alloy steels, the literature shows the mechanism is possible citing SCC in aqueous chlorides as the most common form. However, in the discussion of prevention and control, one of the most reliable methods of preventing SCC of carbon and low-alloy steels is to select a material with a yield strength of less than 100 ksi [16]. The yield strength of carbon steels typically used in non-Class 1 systems are in the order of 30 - 45 ksi. Industry data does not support a widespread problem of SCC in low strength carbon steels, however, there was one reported case suspected to be nitrate induced SCC of carbon steel in a treated water system. For these reasons, SCC of carbon and low-alloy steels is considered not applicable for this tool. SCC in higher strength bolting materials is discussed in the Bolted Closure Tool in Appendix F.

Stainless steels exposed to embedded, buried, or alternately wetted/dried environments (other than normal outdoor environments), are susceptible to cracking since these locations typically contain sufficient aggressive contaminants to provide an environment conducive to SCC. Submerged stainless steel material may also be susceptible to SCC, however, the user is advised to evaluate submerged equipment using the raw water tool (Appendix B of these Mechanical Tools).

SCC of stainless steels exposed to atmospheric conditions is considered plausible only in a saltwater environment and only if the material is in the sensitized condition [6]. Sensitization of stainless steel can be the result of applied, residual, thermal, or welding stresses and may be difficult to accurately assess. Additionally there does not appear to be a threshold level of stress for SCC incidence, the stress level merely dictating the time to failure. However, if stainless steel is known not to be sensitized, then SCC of the material need not be considered a plausible aging effect in an atmospheric environment. There is data in Ref [6] indicating that as-welded Types 304 and 316 resisted SCC, which provides an indication that sensitization does not always lead to SCC. When considering the sensitized question in the logic, it is recommended that SCC of sensitized material be assumed for high carbon content stainless such as Type 304 and 316, but not assumed for low carbon content stainless such as Type 304L and 316L.

3.2.3 Mechanical/Thermal Fatigue

Aging effects of mechanical and thermal fatigue are addressed separately in Appendix H.

3.3 Reduction of Fracture Toughness

3.3.1 Thermal Aging

Thermal embrittlement is a mechanism where the mechanical properties of a material (strength, ductility, toughness) are affected as a result of prolonged exposure to high temperatures. Carbon, low-alloy, wrought austenitic stainless steel, and nickel-base alloys are not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments [13,14,17,18,19]. However, CASS materials are susceptible to thermal embrittlement depending upon material composition and time at temperature. Castings with high ferrite and high molybdenum contents are more susceptible to thermal embrittlement than those with lower values. Recent fracture toughness comparisons between thermally aged CASS and SAW austenitic stainless steel weldments show that the saturated lower bound values of castings are comparable to stainless steel weldments currently in service [20].

CASS materials subjected to sustained temperatures below 250°C (482 °F) will not result in a reduction of room temperature Charpy impact energy below 50 ft-lb for exposure times of approximately 300,000 hours (for CASS with ferrite content of 40%) and approximately 2,500,000 hours (for CASS with ferrite content of 14%) [Figure 1; Reference 20]. When considering a maximum exposure time of approximately 420,000 hours over 48 EFPY, a screening temperature of 482 °F is conservatively chosen below which reduction of fracture toughness is not applicable. This threshold is chosen because, (1) the majority of nuclear grade materials are expected to contain a ferrite content well below 40 %, and (2) the 50 ft-lb limit is very conservative when applied to cast austenitic materials--it is typically applied to ferric reactor vessel materials (e.g., 10 CFR 50 Appendix G).

Since non-Class 1 external surfaces are below the screening threshold of 482°F, CASS materials are not subject to reduction of fracture toughness for the period of extended operation.

3.3.2 Radiation Embrittlement

Radiation embrittlement can result in a decrease in fracture toughness of metals, however, it requires a neutron fluence far exceeding neutron exposures of components and systems in the non-Class 1 category [2,14]. Therefore, radiation embrittlement is considered not applicable.

3.4 Distortion

Distortion may be caused by plastic deformation due to temperature activated phenomena (e.g., creep). In general, distortion is addressed by the design codes and is not considered an applicable aging effect. Creep is not a plausible aging mechanism since the necessary high temperatures do not occur in nuclear plant systems. Creep is not a concern for low-alloy steels below 700F, for austenitic alloys below 1000F, and Ni-base alloys below 1800F [14].

3.5 Galvanized Steel Coating

Galvanized steel is a product used to protect a component or structure from the environment and consists of coating the external surfaces of a carbon steel metal zinc. Zinc is used because of its corrosion resistance in an external environment and by its galvanic protection of the base metal where discontinuities or damage of the coating has occurred [5]. The zinc corrosion products tend to be alkaline thereby neutralizing normal acidic moisture that occurs in industrial environments [7].

In the pH range between 6 and 12 zinc undergoes negligible corrosion under most environmental conditions. Outside this pH range, the increased corrosion rate significantly reduces the usefulness of zinc as a protective coating. When exposed to a water environment, the corrosion resistance of zinc is effective only in this pH range around the neutral point dependent on the buildup of a protective film that is easily dissolved in both alkaline and acidic solutions. In an outdoor environment, on buried components, and in a saltwater environment, the corrosion protection of the protective film is assisted by the buildup of corrosion products deposited out of solution [5]. These deposits do not occur in distilled water and, as a result, the corrosion rates in a distilled water environment are significantly higher than in a contaminated water environment.

Temperature affects the corrosion rate of galvanized steel. Several studies indicate that between 140^{o}F and 200^{o}F, the corrosion products are significantly more conductive than those formed above or below these temperatures. The corrosion products at 185^{o}F were noted to be about 1,000 times more conductive (a measure of impurities) than those at 75^{o}F (in a distilled water environment) [7]. Therefore, the potential for significant degradation of the zinc coating can occur on wetted surfaces in this temperature range. For example, corrosion may occur between insulation and galvanized piping if there is condensation or leakage.

In addition to the effect of temperature on the corrosion of zinc, galvanized carbon steel is also susceptible to the effects of embrittlement at elevated temperatures. It was originally thought that galvanized steel could be used at temperatures up to the melting point of zinc (approximately 785^{o}F) [8]. More recent studies have identified the potential for embrittlement of galvanized steel at temperatures significantly below the melting point of zinc. Observed crack propagation in galvanized steel is typically intergranular and is apparently controlled by a thermal process caused by the self diffusion of the zinc metal. While a major concern at or near the zinc melting point, testing has shown embrittlement can occur that at temperatures below the melting point of zinc. At lower temperatures, the time required for failure increases as does the associated minimum required stress level necessary to cause embrittlement [21].

Based on the data and interpretations included in Reference 21, as well an application upper temperature limit established by the American Galvanizers Association, embrittlement of galvanized steel should be considered a plausible aging mechanism if exposed to temperatures above 400^{o}F.

3.6 Summary of Potential Aging Effects

The aging effects evaluation shows that three aging effects are to be considered for the external surfaces of carbon and stainless steel components. These effects are: 1) loss of material due to one or a combination of aging mechanisms, 2) cracking due to stress corrosion cracking or intergranular attack and 3) reduction of fracture toughness due to thermal embrittlement (galvanized steel only).

Programs that are credited with managing aging predominantly focus on these "effects" and not on the aging mechanisms themselves so it is important that the relationship between the aging mechanisms and the "effects" be identified. The following table provides a summary of the plausible aging mechanisms and their associated "effects" for the external surfaces tool.

Table 3-1 Summary of Potential Aging Effects

MATERIALS	LOSS OF MATERIAL	CRACKING	REDUCTION OF FRACTURE TOUGHNESS	DISTORTION
Carbon Steel	General Corrosion Crevice Corrosion Pitting Corrosion MIC Galvanic Corrosion Wear Fretting	Not Applicable See App. H for Fatigue	Thermal Embrittlement (galvanized steel)	Not Applicable
Stainless Steel	Crevice Corrosion Pitting Corrosion MIC Wear Fretting	SCC/IGA See App. H for Fatigue	Not Applicable	Not Applicable

One significant point in the mechanism and effects relationship here is that the loss of material because of general corrosion is uniform, whereas it is localized for the other corrosion mechanisms. This may be an important factor in determining the effectiveness of detection and management programs. For example, with uniform corrosion, the wall thinning can lead to gross failure (although the rate is very slow and usually predictable). With localized loss of material, the material loss is concentrated with relatively small material weight loss leading to a through-wall failure (although the rate can be very fast and unpredictable). Through-wall failures associated with localized corrosion are generally pin-hole type leaks, allowing time for leak detection before impairing component or system function.

Thermal embrittlement is a loss of fracture toughness of galvanized steel at high temperatures (above 400^{o}F). This aging is not detectable by visual inspection and a knowledge of component temperature history is necessary to determine at what point the loss of material strength renders the material inadequate to perform its design functions.

3.7 Applicable NRC Generic Correspondence

The NRC generic correspondence (Circulars, IE Bulletins, Information Notices, and Generic Letters) were reviewed for correspondence related to the external surfaces of components. Several entries were found that related to fatigue failures of small bore attached piping and corrosion of threaded fasteners. Thermal and mechanical fatigue correspondence will be discussed in Appendix H. Correspondence related to boric acid leakage is addressed in Appendix F since bolted enclosures are the source of most boric acid leakage. However, it is recognized that boric acid leakage can extend beyond the boundary of the bolted enclosure tool.

Two other Information Notices relating to external surfaces are discussed below.

NRC Information Notice 80-05: Chloride Contamination of Safety-related Piping and Components
Bechtel Power Corporation determined at the Wolf Creek Project that a fire retardant coating is potentially corrosive in contact with stainless steel. Albi "Duraspray" is used to fireproof exposed structural steel in some power plants. It does not appear to affect unprimed inorganic zinc coated, or galvanized steel, however, it may be corrosive to stainless steel, bare aluminum, or copper. The Notice advised to protect all affected material from overspray and droppage of cementitious oxychloride materials.

NRC Information Notice 85-34: Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping
In 1984, Pilgrim Nuclear Power Station reported seven through-wall cracks in 50 feet of type 304 stainless steel piping. The 1 inch piping was installed in a horizontal position in the post-accident sampling system. The lines were intended to have a slope for draining, but interface requirements led to a horizontal line with sagging. The pipe carries gas samples and heat tracing was used to keep it dry. During evaporation, the chlorides present in the water concentrated where the pipe sagged. Repeated evaporation will lead to a buildup of chemicals and may eventually cause corrosion of the piping that is kept hot by the heat tracing. Although this was a case of cracking from the inside-out, the external heat tracing environment initiated the concentration of chlorides which promoted the stress corrosion cracking.

4. FLOW DIAGRAN DEVELOPMENT

Figure 1 presents the logic diagram to be used to evaluate the external surfaces of carbon steel and stainless steel components and includes consideration of galvanized steel as a special coating. The following assumptions, general discussion, and tool description apply to this logic tool.

4.1 Assumptions

1. Components that are submerged, in the "splash" zone of raw water sources, or continuously wetted, are essentially subjected to what constitutes a raw water environment. The external surfaces of these components should be evaluated using Appendix B of these tools which considers the aging effects applicable to such fluid.

2. Oxygen level is a significant parameter in many aging mechanisms. This tool assumes that the level of oxygen in the atmosphere and surrounding buried components is at least above the threshold value to cause corrosive effects.

3. Atmospheric environments contain aggressive chemical species including oxygen, halides, sulfates, and other aggressive corrosive substances that can influence the nature, rate, and severity of corrosion effects. However, it is assumed that these contaminants cannot be concentrated to levels that will promote corrosive effects unless subjected to factors such as cyclic (wet-dry) condensation, contaminated insulation, accidental contamination, or leakage areas.

4. The environment surrounding buried or embedded equipment usually contains both oxygen and other aggressive species. For the purposes of this tool, the buried/embedded path assumes that a component is exposed to both oxygen and/or other chlorides, halides, sulfates, etc. (unless paintings or coatings are utilized).

5. Crevice corrosion requires some type of crevice (an opening usually a few thousandths of an inch or less in width) to occur. It is unreasonable to expect an evaluator to respond to a question of whether or not a crevice exists within a system or component. The logic, therefore, will assume conservatively that the potential exists for crevices in all components and systems.

6. Some aging effects are the result of mechanisms that require stresses to operate. It is unreasonable to expect an evaluator to establish the presence of stresses resulting from the manufacturing process or post- installation welding for every component under consideration. In these cases, the logic conservatively assumes that the threshold stress exists for the mechanism to occur.

7. The stainless steel logic determines SCC to be a plausible aging mechanism in a saltwater environment only when the material has been sensitized. This necessary condition is based

on extensive outdoor testing of stainless steel as discussed in Section 3.2.2 of this Appendix and described in Reference [6]. Some plants have replaced components and/or piping with non-sensitized stainless steel to preclude SCC and this tool logic rules out SCC as plausible when the material is not sensitized.

8. Microorganisms of various types that influence corrosion either directly or indirectly are assumed to exist for the buried environment.

9. Coatings and/or linings for buried or embedded equipment are not automatically credited as for above ground equipment since the methods, techniques and preservation are varied and more plant specific. Each utility must assure that a program is in place to verify the integrity of the coating. This tool defers the responsibility to the utility rather than generically excluding aging.

10. The zinc coating on galvanized steel has demonstrated very high rates of corrosion in a distilled water environment between 140 and 200^{o}F. A similar environment can occur when condensation or leakage from insulated pipe results in a wetted condition between the insulation and the galvanized material. The tool logic provides for accelerated depletion of the zinc coating for galvanized steel under such conditions.

4.2 General

The Mechanical Tools provide a method to identify applicable aging effects for systems and components which are required to undergo an aging management review in compliance with the license renewal rule. Implementation of these tools at the various sites will result in the identification of plant equipment and aging effects that must be managed during the renewal period. Demonstration of the adequacy of aging management programs is outside the scope of this tool and will be addressed separately.

These tools will identify potential aging effects and also direct the user to areas in the system where these effects might be preferentially manifested. The aging degradation discussion in the previous sections identified numerous aging mechanisms and their associated aging “effects” which potentially can occur. This logic tool, Figure 1, then guides the user to determine, based on specific system or component materials, environment and/or operating conditions, whether these effects are applicable. This tool and the descriptions in the following sections address the “effects” of aging on the external surfaces of carbon and stainless steels. This tool is organized such that individuals utilizing the tool do not require a detailed knowledge of aging mechanisms, or their effects. The logic does, however, require that the user be familiar with the materials of construction and the various environments.

The evaluation logic groups various aging effects such as loss of material, cracking, etc. to allow efficient disposition of equipment. Implementation of the tool documents the disposition of aging mechanisms, the resultant aging effects, and provides a link to the program evaluations and Aging Management Review (AMR) phase. The results identify the effects which must be managed and can help guide how and where to implement aging management programs.

4.3 Tool Description

Figure 1 contains the logic to evaluate aging effects for the external surfaces of carbon and low-alloy steels and austenitic stainless steels. It also contains the logic where accelerated aging effects for the external surfaces of galvanized steel can be identified.

The upper branch evaluates carbon and low-alloy steel and the lower branch evaluates austenitic stainless steel. Both carbon and austenitic stainless steel components are subjected to the logic pertaining to loss of material because of wear. Galvanic corrosion is only applicable to carbon and low alloy steel. Galvanized steel is not subjected to galvanic corrosion logic because it provides galvanic protection of the carbon steel even under degraded conditions.

Stainless Steel

The first decision block in the stainless steel logic asks whether the external surface is exposed to an aggressive environment. This block is intended to remove from further aging consideration all stainless steel material which is not exposed to a harsh environment. Stainless steel which is in a sheltered locations and not subject to either wetting/drying or frequent moisture exposure can be excluded from further consideration. Controlled indoor environments as well as material that is coated or painted fits this category. A determination of whether the exterior surface is subjected to a buried, embedded, or alternately wetted/dried environment is then made. The question of alternately wetted/dried does not include exposure to rain only but is included to cover situations where aggressive species can concentrate such as buried, embedded, or alternately wetted/dried conditions where the source fluid could contain contaminants. Alternate wetting and drying resulting from rain has shown a tendency to "wash" the exterior surface material rather than concentrate contaminants [6]. Examples of this type of wetting include insulated components subject to sweating, tanks/components subject to cyclic condensation when frequently filled from an external source, or chronic leakage areas. Components subjected to a wetted environment are susceptible to general, pitting, crevice corrosion, and SCC/IGA. MIC damage is also a concern if the component is buried or otherwise in contact with a raw water source.

The "no" path includes stainless steel material subjected to either indoor or outdoor atmospheric conditions. Stainless steel is not susceptible to pitting, crevice or other forms of corrosion in under these conditions unless exposed to a saltwater environment. However, the potential for SCC/IGA is a concern for sensitized material in a marine environment (i.e. saltwater environment) [6]. Although material can be sensitized by various means, the predominant field sensitization is caused by welding, without subsequent solution heat treatment. The logic addresses sensitized material for this condition for two reasons: 1) The susceptibility in a non-wetted environment is fairly low but cannot be completely eliminated from consideration, and, 2) some plants have specifically replaced or installed piping and other components in such an environment with material known not to be sensitized. The logic provides for a non-plausibility determination of SSC/IGA under those conditions.

Carbon and Low Alloy Steel

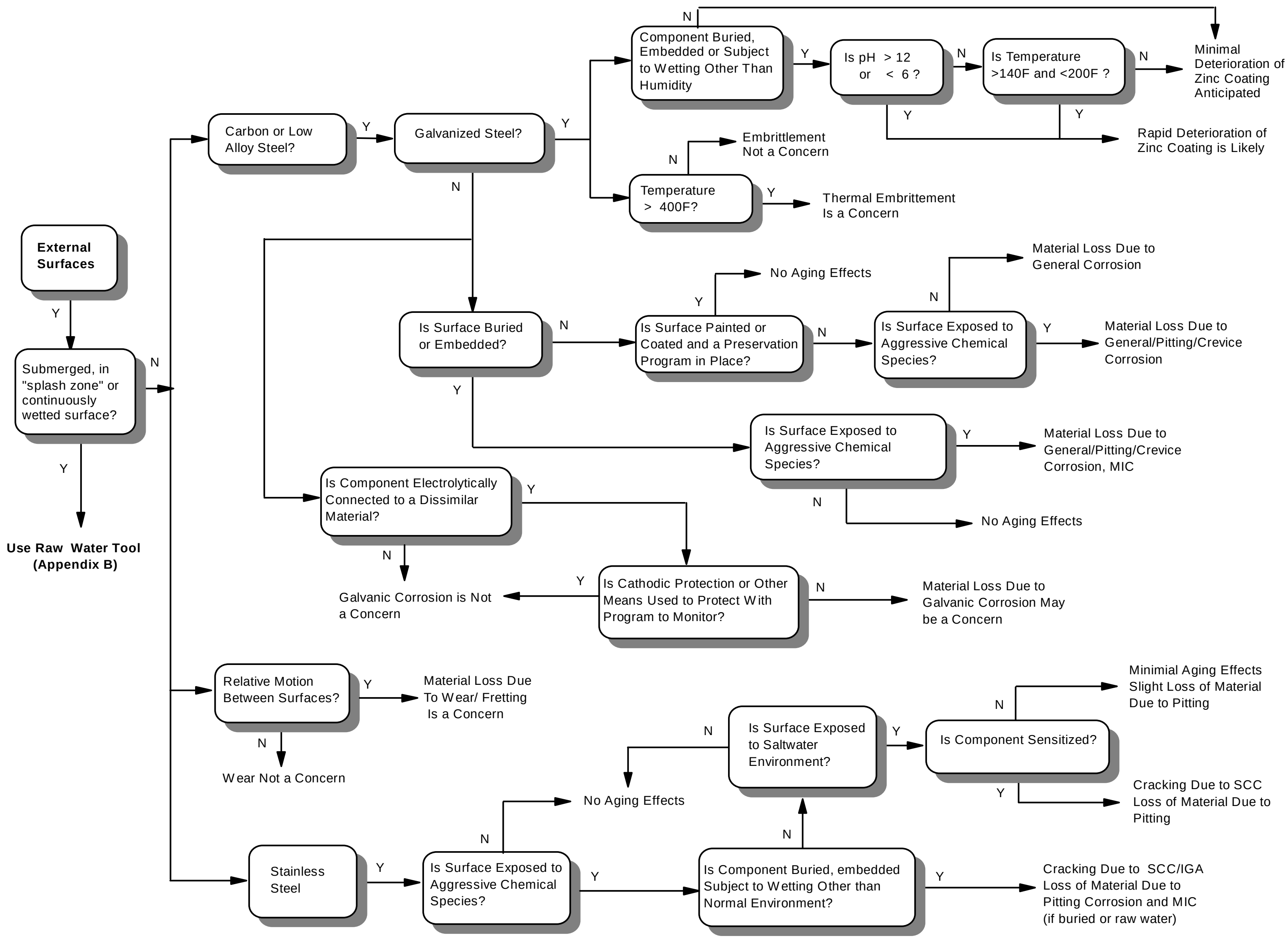
The carbon and low alloy steel logic first separates carbon and low alloy steels from galvanized steel. The carbon steel logic branch precludes corrosive effects for painted or coated surfaces provided that an effective preservation program is in place. The effectiveness of such a program would have to be demonstrated through aging management programs as a follow-on activity to this aging effects identification. Coatings and/or linings for buried components are not addressed in the logic because the methods, techniques, and preservation are varied and more plant specific. This does not preclude the possibility of an effective program for buried components, but only promotes a plant-specific aging management discussion rather than a generic application. As discussed in assumption 3 in Section 4.1 of this Appendix, the question regarding aggressive species for buried and embedded equipment must consider oxygen as an aggressive species. In the logic for equipment neither buried nor embedded, oxygen should not be considered an aggressive species when answering this logic question. The “no” path from this block inherently assumes oxygen is present.

Galvanized Steel

The galvanized steel branch provides the logic to identify aging specific to galvanized steel that results in accelerated degradation of the zinc coating. Although other paintings and coatings are utilized, the widespread use of galvanized steel for environmental protection was a factor in including specific logic in this exterior surface tool. Because this logic addresses integrity of the galvanized steel and essentially discerns between rapid deterioration and minimal degradation, this upper branch does not identify specific aging effects of the base carbon steel. Where minimal degradation of the zinc coating is identified, it does not preclude the necessity for a program to assure the integrity. Conditions resulting in expected rapid deterioration of the coating indicate over and above that anticipated during design and installation and thus requires more immediate attention. If depletion or rapid deterioration of the zinc coating is identified using the galvanized steel branch, aging effects for the base material can be identified by following the carbon steel logic when the coating is no longer intact.

The lower branch of the galvanized steel logic addresses the potential embrittlement of galvanized steel at temperatures above 400^{o}F. Thermal embrittlement of the material at these temperatures affects the base material and not just the zinc coating. Interactions between the zinc and carbon steel base material can result in embrittlement of the base material at high temperatures resulting in a loss of fracture toughness of the base material.

Figure 1 External Surface Tool



5. CERTIFICATION

This appendix is an accurate description of aging effects of carbon and stainless steel external surfaces prepared for the BWR Owners Group License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

David J. Firth 8/14/99

David J. Firth Date
GLRP Project Manager

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Appendix F-Bolted Closures

Bolting applications within the scope of license renewal may be divided into pressure boundary bolting and structural and component support bolting. Pressure boundary bolting applications, which are addressed in this appendix, include bolted flange connections for vessels and heat exchangers (i.e., manways and hand holes), flanged joints in piping, body-to-bonnet joints in valves, and pressure retaining bolting associated with pumps and miscellaneous process components; these bolted joints are hereafter referred to as bolted closures. Structural and component support bolting is not addressed in this appendix but is included in the structural tools being developed separately.

CONTENTS

1. INTRODUCTION

1.1 Purpose

Bolting applications within the scope of license renewal may be divided into pressure boundary bolting and structural and component support bolting. Pressure boundary bolting applications, which are addressed in this appendix, include bolted flange connections for vessels and heat exchangers (i.e., manways and hand holes), flanged joints in piping, body-to-bonnet joints in valves, and pressure retaining bolting associated with pumps and miscellaneous process components; these bolted joints are hereafter referred to as bolted closures. (Structural and component support bolting is addressed in the structural tools being developed separately.) A bolted closure includes the constituents of a bolted joint, e.g., seating surfaces (i.e., flange set surfaces), gasket (if applicable), and pressure retaining bolting. Only non-Class 1 bolted closures are addressed in this document. Aging management for bolted closures within the Class 1 ISI boundary for the B&W plants are addressed in the B&WOG generic topical reports.

Aging management programs required to assure bolted closure integrity will be addressed on a plant-specific basis using general recommendations provided in Section 4.0. The scope of bolted closures is discussed in Section 2.0, and typical aging effects that may cause loss of mechanical closure integrity are discussed in Section 3.0.

1.2 Regulatory Bolting Safety Issue

The NRC noted that from 1964 to the early 1980s an increased number of reported failures of high-strength bolting in safety-related equipment and Class 1 component supports [1]. The most common failures of pressure retaining bolting in safety-related equipment were attributed to boric acid corrosion wastage and a few instances of stress corrosion cracking (SCC). The most frequently observed failure mode for structural bolting was SCC of low-alloy quenched and tempered steels and maraging steels.

The bolting safety issue originally was an integral part of the NRC's unresolved safety Issue A-12, which dealt with fracture toughness concerns related to steam generator and reactor coolant pump supports. The NRC then recognized the need to assess bolting safety issues separately and issued Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants," The safety aspects of GSI 29 included concerns over degradation of fasteners that comprise critical bolting applications in nuclear power plants. In June 1982, the NRC issued IE Bulletin 82-02 which required responsive actions by all pressurized-water-reactor licensees because threaded fastener failures had shown an increasing frequency of occurrence. In response to the NRC concerns over fastener integrity, the Atomic Industrial Forum (AIF) joined with the Material Properties Council (MPC) to from the Joint AIF/MPC task Group on Bolting in June 1982. When the NRC prioritized generic issues in November 1982, GSI 29 was assigned a high priority.

The Joint AIF/MPC Task Group on Bolting developed a comprehensive industry program to resolve GSI 29. Specifically, a 19-task Generic Bolting Program was developed and the Electric Power Research Institute organized a matrix-managed Generic Bolted Joint Integrity Program to carry out the recommendations contained in the task list. Results of the 19-Task program are contained in a two-volume EPRI report [2] that was published in April 1988. The work completed to resolve GSI 29, as documented in the EPRI Report [2], showed that (1) existing requirements, (2) leak-before-break criteria for Class 1 joints, and (3) existing programs should minimize the risk resulting from the failure of safety-related bolting in current plants. In addition, the NRC staff concurred with the recommendations and Guidelines provided in Section 1, Volume 2 of EPRI NP-5769 [2].

A major finding of the Generic Program was that the design of critical closure joint bolting involves enough redundancy to ensure that there is no pressing concern regarding bolting integrity. In addition, it was recommended that licensees implement plant-specific bolting integrity programs that reflect the information and recommendations made by the industry sponsored programs on bolting issues. While the focus of the study was on Class 1 bolted closures, all safety-related closures were considered.

2. BOLTED CLOSURES-SCOPE

The scope of the bolted closure tool includes surfaces of bolted flange connections for vessels (i.e., manways, hand holes, etc.), flanged joints in piping, body-to-bonnet joints in valves, and pressure retaining bolting associated with pumps and miscellaneous process components. As discussed in Section 2.0 of the main document, gaskets, packing, and seals are within the scope of license renewal but may be excluded from aging management review provided the evaluator can demonstrate that these items are replaced upon performance or condition monitoring, or are replaced on qualified life or specified period of time.

Pressure boundary bolting, typically referred to as fasteners, include nuts, bolts, studs, and capscrews. Typical fastener materials include carbon steel--A307, A36, SAE J429, A325, A449, and A490; low alloy steel--A193 B7, B7M, A 320 L7, L7M, L70; and austenitic stainless steel--A193 B8 and B8M, and A320 B8 and B8M.

Class 1 to Non-Class 1 Boundary

The Class 1 ISI boundary typically extends to and includes either the first or second isolation valve or a flow restricting orifice in branch lines attached to the reactor coolant system main coolant piping and other major RCS (PWR's) or primary system (BWR's). components. For flanged connections that define a Class boundary, the Class 1 portion includes the face of the first flange (the bolts may be considered part of the non-Class 1 piping). For threaded joints, the Class 1 boundary includes the threaded joint in screwed connections.

3. AGING EFFECTS

The governing aging effect to consider for bolted closures is loss of mechanical closure integrity. Loss of mechanical closure integrity may be attributed to one or more of the following aging effects that may be applicable to the bolted joint: loss of pre-load, cracking of bolting material, loss of bolting material, and reduction of fracture toughness of bolting material. In the discussion presented below, aging mechanisms that may result in the aforementioned aging effects are discussed. The mechanisms discussed are not intended to represent a comprehensive list of aging mechanisms and are provided for general information only. The discussion of aging mechanisms definitions are extracted from the EPRI manuals on good bolting practices [3,4].

3.1 Loss of Pre-Load

The preload in a bolt is often less than expected and may be attributed to, but not limited to, one or more of the following effects: embedment, cyclic load embedment, gasket creep, thermal effects (e.g., yield stress effect, modulus of elasticity effect, and stress relaxation), and self loosening. These effects are discussed at length in References 3 and 4 and are briefly summarized below. Many of these effects are adequately addressed when the joint is made up and may not be applicable aging effects since they would be observed during the current license term.

3.1.1 Embedment

Fastener and joint surfaces are microscopically rough. When first assembled, these surfaces (nut, bolt threads, joint members, etc.) only contact each other on high spots. When initially loaded the high spots tend to creep and flow. Preload is lost as the parts settle in together.

3.1.2 Cyclic Load Embedment

Joints subjected to cyclic loads, especially large loads, will embed and relax more than joints under static loads. If external loads approximate the yield strength of the bolt, preload losses of 25% or even 50% may occur.

3.1.3 Gasket Creep

Gaskets must be partially plastic to function properly and will creep after initial loading. Preload loss at room temperature may be 2-5% and will occur in 10 to 20 minutes after initial loading.

3.1.4 Thermal Effects

A joint subjected to a change in temperature can lose preload. Differential expansion between bolts and joint members can increase stresses and increase embedment or gasket creep. The bolt may expand away from the joint. The gasket may be compressed beyond the original compression and, due to hysteresis, won't fully recover as the temperature change is reversed. Creep of bolts and gaskets can be promoted by high temperature through a process called stress relaxation.

3.1.5 Self Loosening

Vibration, flexing of the joint, cyclic shear loads, thermal cycles and other causes can cause whole or partial self loosening of a fastener. Self-loosening is not an applicable aging effect since it would be detected early in component service life and actions are taken to prevent recurrence.

3.2 Cracking of Bolting Materials

Cracking of bolting materials may be attributed to stress corrosion cracking and/or fatigue. Stress corrosion cracking is a condition in which a fastener that is statically loaded well below the material yield strength can suddenly fail. SCC bolted closure fastener failures have occurred in materials with apparently nominal chemical and mechanical properties [2]. Service and laboratory failures have been observed for bolting materials subjected to water or steam environments containing various contaminants. Carbon and alloy steel fasteners are not intentionally exposed to water or steam, but inadvertent exposure may result from gasket leaks. If leakage is combined with contaminant species, such as sulfides or chlorides, an aggressive environment that can promote SCC may result. Decomposition products from lubricants and sealant compounds injected into leaking closures may produce environments capable of causing SCC in stressed carbon and alloy steel fasteners.

A common factor in several of the reported failures appears to be the use of lubricants containing MoS_2[2]. Laboratory tests indicate that H_2S may result from MoS_2 decomposition in aqueous environments; however, there is no data that conclusively show that MoS2 decomposition will cause SCC. Data generated by the oil and gas industry show that, even at low temperatures, H_2S will cause SCC in carbon and alloy steel fasteners. Therefore, MoS_2-induced SCC is viewed as a possible explanation for some of the reactor coolant pressure boundary bolted closure failures. However, most bolting is normally in a dry environment and is coated with a lubricant; in general, environmental conditions that may lead to SCC are not expected to occur.

Cracking of bolting due to fatigue is typically characterized by the following: (1) the failure is sudden with little or no necking-down of the part, (2) the component has been subjected to cyclic tensile loads, and (3) usually the cyclic loads are well below the material tensile strength. The susceptibility to fatigue depends upon many factors including the properties of the fastener materials, fastener processing, defects in the material, stress levels, and the shape of the fastener. However, cracking of bolting due to thermal fatigue is not expected to be a concern for non-Class 1 bolting applications due to low operating temperatures compared to the Class 1 bolting applications. High cycle fatigue is not a concern for license renewal since it would be discovered during the current license period in most cases where systems are frequently operated. For standby systems subject to periodic testing, such as HPCI, failure caused by high cycle fatigue may be a longer term issue. Evaluation of high cycle fatigue for infrequently used systems is not addressed and should be considered on a case-by-case basis by the user of this document.

3.3 Loss of Material-Corrosion of Bolting Materials

Loss of material due to boric acid wastage is the most common aging affect that has been observed for ferritic fasteners. Stainless steel fasteners are immune to loss of material due to general corrosion. Most bolting is normally in a dry environment and is coated with a lubricant and general corrosion is not expected. General corrosion of ferritic fasteners has only been observed due to leaking joints.

3.4 Reduction of Fracture Toughness

Reduction in fracture toughness due to irradiation embrittlement is not applicable to the non-Class 1 bolted closure scope since these closures are not within the beltline region of the reactor vessel. Some precipitation hardening martensitic stainless steels (e.g., 17-4 pH) may be susceptible to thermal embrittlement [2] in high temperature applications which could lead to a reduction in fracture toughness.

3.5 Operating Experience and Generic Communications

3.5.1 NPRDS Review

A review of NPRDS was performed to determine documented instances of loss of mechanical closure integrity of bolted connections for non-Class 1 mechanical systems. As discussed in Appendices A and B, failures of gaskets, packing, and O-rings are the most common failure mode for bolted closures. The failures were detected during ISI, IST , Surveillance Testing, and system walkdowns.

3.5.2 NRC Generic Communications

Information Notices

IN 80-29: Broken Studs On Terry Turbine Steam Inlet Flange
When removing the governor and stop valve on the Unit 1 steam driven emergency feedwater pump at Arkansas Nuclear One for repair of a steam leak at the steam inlet flange Arkansas Power and Light discovered that five of the eight studs securing the

flange were broken. The failed studs are 3/4 in. diameter by 3-1/2 in. long and are thought to be of ASTA-193 grade B7 steel. The turbine flange bolting is generally covered with insulation and not visible for inspection. From the information available, the bolting has not been removed or inspected since installation seven to eight years ago. Licensees are encouraged to carefully examine insulation in the flange to turbine casing region for evidence of leakage and consider inspection of the turbine steam inlet flange bolting. Further, during surveillance testing, care should be taken to observe if abnormal vibration or other transients occur which could promote loss of bolting integrity.

Generic Letters

GL 91-17--Bolting Degradation or Failure in Nuclear Power Plants.

GL 91-17 provided licensees with information on GSI 29 which addressed degradation of all safety-related bolts, studs, embedments, machine cap screws, and other threaded fasteners. The NRC concluded that existing requirements, in combination with actions taken in response to industry initiatives, are sufficient to assure integrity of safety-related bolting.

IE Bulletins

BL 82-02--Degradation of Threaded Fasteners in Reactor Coolant Pressure Boundary of PWR Plants.

BL 82-02 alerted licensees to instances of degradation of threaded fasteners in closures in the reactor coolant pressure boundary and required appropriate corrective actions. Degradation of RCPB fasteners was reported at selected plants and resulted from boric acid wastage at bolted closures. In addition, BL 82-02 reported that sealant compounds, such as Furmanite, may contain variable compositions of halogens and sulfur which are leachable and promoters of SCC. BL 82-02 also reported that certain lubricants may contain a significant level of sulfide constituent, which can promote SCC. The actions taken in response to BL 82-02 were submitted to the NRC by each of the participating utilities.

4. DEMONSTRATION OF AGING MANAGEMENT

In order to conclude that loss of mechanical closure integrity is not an applicable aging effect, the evaluator must identify materials that comprise the bolted closure and evaluate the aging effects discussed in Section 3.0.

As discussed in Section 1.2, the most common failures of pressure retaining bolting in safety-related equipment were attributed to boric acid corrosion wastage and a few instances of stress corrosion cracking (SCC) of ferritic materials. In addition, review of NPRDS data indicates that failures of gaskets, packings, and O-rings led to the majority of observed instances of loss of mechanical closure integrity for non-Class 1 bolted closures. Therefore, most instances of loss of mechanical closure integrity for non-Class 1 bolted closures were attributed to failures of gaskets, packings, and O-rings, which subsequently led to degradation of bolted closure metallic material, and not to direct age-related degradation of bolted closure metallic materials.

Plant-specific programs implemented in response to IE Bulletin 82-02 and Generic Letter 91-17 that apply to the non-Class 1 bolted closures should be continued through the period of extended operation. Recommendations of program technical elements to manage mechanical closure integrity are provided below.

1. Bolted closures within the scope of license renewal should be identified.

2. In order to dismiss gaskets (if applicable), packing, or O-rings from aging management review, two options should be considered: 1) implement either a performance or condition monitoring program, or 2) demonstrate that the specified items are replaced based on a qualified life or a specified period of time.

3. Specific bolting materials and their susceptibility to various aging mechanisms are not evaluated in this tool; therefore, the evaluator should rely upon the conclusions in Reference 2 regarding sufficient redundancy to ensure joint integrity and leak detection as a means of detecting loss of mechanical closure integrity for bolted closures. Leak detection may take the form of system hydrostatic tests and system inservice testing required by ASME Section XI, operator walkdowns, and surveillance testing.

4. Bolting integrity programs instituted as a result of IE Bulletin 82-02 and GL 91-17 that affect the non-Class 1 scope of bolted closures should be continued through the period of extended operation.

5. Site specific Aging Management Programs (AMP's) will identify the program element commitments for the extended period of operation. These program elements should consider all current and historic programs that address loss of mechanical closure integrity.

5. CERTIFICATION

This appendix is an accurate description of general recommendations for aging management of bolted closures within the scope of license renewal.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date

GLRP Project Engineer

This appendix contains general information on aging management of bolted closures and is approved for incorporation in the Implementation Guideline. Should the participating utilities require additional guidance to determine specific aging effects and mechanisms based upon materials of construction and operating environment, additional review of this appendix by Materials personnel will be required.

D J Firth 8/14/99

David J. Firth Date

GLRP Project Manager

6. REFERENCES

1. "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," NUREG-1339, June 1990.

2. "Degradation and Failure of Bolting in Nuclear Power Plants," Volumes 1 and 2, EPRI NP-5769, Project 2520-7, Final Report, April 1988.

3. John Bickford and Michael Looram, Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel, Volume 1: Large Bolt Manual, EPRI-NP-5067, 1987.

4. Daniel A. Van Duyne, Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel, Volume 2: Small Bolts and Threaded Fasteners, EPRI, December 1990.

Appendix G--Heat Exchangers

This appendix provides the guidance, exceptions, and clarifications for using the "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers" to assist in the identification of aging effects of heat exchangers defined to be within the license renewal scope. It provides a summary of the aging effects identified in the aforementioned guideline and identifies inconsistencies between that guideline and the logic described in the other Mechanical Tool Appendices.

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LIST OF TABLES

1. INTRODUCTION

1.1 Background

In the development of the other Mechanical Tools for the evaluation of aging effects, the approach to identify aging effects is less complex than the case for heat exchangers. That is, most components can be evaluated from the standpoint of a single material in a single environment (e.g., carbon steel material in a raw water environment). For heat exchangers, there are usually multiple materials and multiple environments. Although the Mechanical Tools can be used for heat exchangers depending on the specific material/environment combination, it is convenient to address all heat exchanger aging effects with one source.

The "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers" [1] prepared by MDC-Ogden provides a single source to evaluate the many variables associated with aging of heat exchangers. After a review of the technical content of the Aging Management Guideline (AMG), the decision was made to use selected portions of the AMG for aging effect identification, with appropriate guidance as outlined in this appendix.

1.2 Scope

This appendix provides a review of the aging effects for heat exchangers that are within the scope of license renewal. The scope of this appendix includes the boundary of the heat exchangers up to their interface with the system piping. The aging effects for the external surfaces of the heat exchangers are evaluated in Appendix E. The aging effects for the bolted closures (i.e. flanged connections and bolting) are evaluated in Appendix F. The fatigue related effects are evaluated in Appendix H.

Plant-specific lists of systems within the scope of license renewal were reviewed to determine the types of heat exchangers that may be subject to an aging management review. In most instances the heat exchangers that may be subject to an aging management review are within the scope of the AMG (Table 1-2 of Reference 1). This appendix provides guidance to the evaluator for the review of heat exchangers by summarizing the AMG results in a format more consistent with the other Mechanical Tools. This summary of results in a material/environment format, and the subsequent guidance, provide the information necessary to evaluate heat exchangers that are not within the scope of the AMG.

This appendix endorses, with exceptions and clarifications (as detailed in Section 5 of this appendix), Sections 1 through 4 of the AMG. Discussions regarding aging management programs, which are presented in Section 5 of the AMG, have not been reviewed in detail. The generic results and recommendations of Section 5 of the AMG may be of use to the users of these Mechanical Tools in their discussion of plant-specific aging management programs; however, this appendix only addresses the aging effects evaluation of heat exchangers.

Section 3.6 of the AMG, "Operating and Service History," which includes a review of NRC LERs, NPRDS, NRC generic correspondence, and operating plant data is considered applicable as used in the development of aging evaluation logic.

The definitions of process fluid environments in the AMG are similar to the definitions in the Implementation Guideline and Mechanical Tools. One notable exception includes the definition of treated water. Where these tools classify all treated water as one category, the AMG evaluates treated and closed cooling water separately. In the AMG, both treated and closed cooling water are assumed to be filtered and demineralized but not deaerated. Additionally, closed cooling water in the AMG is assumed to contain corrosion inhibitors and/or biocides. (In PWR applications, the only application of treated water evaluated in the AMG is the Spent Fuel System. The remainder of the PWR filtered and demineralized water systems are evaluated as closed cooling systems.) This difference by itself, however, does not result in inconsistent results between the AMG and these tools. The treated water tool includes logic to evaluate water with and without added corrosion inhibitors and/or biocides.

1.3 Purpose and Objective

The purpose and objectives of this appendix are to provide directions, exceptions, and/or clarifications for using the AMG for heat exchangers to assist in the identification of aging effects of heat exchangers defined to be within the scope of license renewal.

The appendix includes:

- a summary guideline to using the AMG evaluations and this appendix
- a summary of applications, materials and environments covered by the AMG
- a listing of the various BWR and PWR heat exchangers included within the AMG together with the major tube/shell materials and the fluid environment assumed in the AMG
- exceptions and/or clarifications to the evaluation logic developed in the AMG
- a summary of the AMG evaluation results in a material/environment format

2. GUIDANCE FOR HEAT EXCHANGER EVALUATIONS

The Sandia Aging Management Guideline (AMG) for Heat Exchangers provides a detailed evaluation of the aging effects applicable to a specific set of heat exchangers. Based on various inputs, a set of heat exchangers was identified in the AMG that 1) are within the scope of license renewal, and 2) are expected to require aging management review under the license renewal rule requirements. (Section 3.0 of this appendix provides a summary of the heat exchangers included in the AMG evaluation.)

The Sandia AMG utilizes an approach similar to the other Mechanical Tool Appendices for evaluating the effects of aging. The approach is a typical materials/environment evaluation where the significance of specific aging effects is based on the materials used and the fluid environment to which these materials are subjected. The AMG also makes assumptions concerning the design of components, water chemistry of the various environments and system parameters (such as flow rates) during the evaluation of aging effects.

The AMG method is similar in approach to an aging management review that would be conducted if the other appendices of these Mechanical Tools were applied to heat exchangers. Since the other Mechanical Tool Appendices were not intended to address heat exchangers, the other appendices differ slightly from the heat exchanger AMG with regard to the treatment of wear and fouling. In the other Mechanical Tools, wear is considered the result of performance of an active function and is not identified as an applicable aging mechanism, whereas the AMG treats wear as a significant aging mechanism for some heat exchanger components. Wear and fretting on internal pressure boundary surfaces is under review by the NRC and industry. The user of this tool should review regulatory correspondence and industry technical reports, etc., after the issuance of this document to determine if heat exchanger pressure boundary items should be evaluated for wear and fretting.

Fouling and its effect on heat transfer must be considered for license renewal. The AMG contains a comprehensive treatment of fouling in heat exchangers and should be used to evaluate reduction of heat transfer. The other Mechanical Tool Appendices do not address the heat transfer function.

An alternative to applying the Sandia AMG in its entirety is to perform the aging effects evaluation using the other material/environment tools with additional consideration of wear and fouling as aging effects. If this alternative is used, the sections in the AMG dealing with fouling and wear provide excellent guidance to the identification of materials and sub-components susceptible to reduction of heat transfer, wear and fouling. The AMG evaluates many material/environment combinations and identifies all significant aging effects. The aging effects for the heat exchanger subcomponents are described in detail in Section 4.3.2 of the AMG for the material and environment combinations. Tables 6-2 through 6-7 summarize the significant aging effects for the heat exchangers identified in the AMG.

Section 4.3.2 of the AMG contains information that can be used to identify the aging effects of specific material and environment combinations. However, caution must be used when applying the summary of aging effects identified in Tables 4-3 through 4-8 of the AMG. The AMG tables summarize the aging effects based on the environment and sub-component only. When a subcomponent has more than one material the aging effects for all materials are not identified in the tables. In order to determine the aging effects of a specific heat exchanger material, it is necessary to refer back to the written descriptions in Section 4.3.2. For example, AMG Table 4-7 identifies general corrosion and IGSCC as significant for the tubes/coils in a raw water environment. Stainless steel is susceptible to IGSCC in a raw water environment, however, it is not susceptible to general corrosion in that environment. Conversely, carbon steel in a raw water environment is susceptible to general corrosion but is not susceptible to IGSCC.

For those combinations which are not directly or indirectly covered by the AMG, an alternative approach to identifying significant aging mechanisms must be used. If the logic developed in the other Mechanical Tool Appendices is applied, wear and fouling must also be considered since the logic for these aging effects is not included. The summary tables in Section 6 of this appendix provide an indication of the materials and environment combinations for which wear and fouling may be significant aging mechanisms.

There are two approaches that can be used to identify aging effects for heat exchangers, i.e., using this appendix or the Sandia AMG. A third option is to use the other Mechanical Tool appendices for a majority of the evaluation and to use the AMG for the balance of the issues. All three methods are described briefly below. Because of the many different materials and some unique environment considerations, it may not be possible to identify all aging effects for all heat exchangers using these methods. A small number of plant-specific applications may still require independent aging effects evaluations. The tables in Section 6 of this document combined with the AMG and the other Mechanical Tools, should provide the information necessary to complete the identification of applicable aging effects.

Depending on the heat exchanger design and materials of construction one of the three methods to identifying the significant aging effects for heat exchangers will be optimal. if the AMG heat exchanger material, environment and application match exactly the heat exchanger being evaluated, the best way to evaluate aging will be to use the AMG. The second method is to use the modified AMG summary tables in Section 6 of this appendix to identify the significant aging effects. This second method is appropriate if the materials and environment are covered in the AMG evaluation and included in these summary tables. Due to the generic nature of this data, some plant specific work may be required when using this option to provide consistency with the other Mechanical Tool appendices. The third method where the heat exchangers are evaluated using only these

Mechanical Tools, determines aging effects based on the materials and environments included therein. This method may require significant additional work since some aging effects specific to heat exchangers are not covered in the other Mechanical Tools.

A utility may decide to use more than one method to evaluate the various heat exchangers. Flexibility is a fundamental attribute of this tool.

Method 1: Evaluations for Specific Heat Exchangers using the AMG.
The AMG evaluates specific heat exchangers, environments and materials. Before using the AMG the following inputs must be compiled: materials of construction, fluid or air environment (based on the AMG classifications), and the heat exchanger design. When there is an exact match to a heat exchanger in the AMG, the results of the AMG aging effects identification are valid. The summary tables for the environments and heat exchanger components listed in the AMG tables 4-3 through 4-8 may identify aging effects that do not apply to a specific application because all significant aging effects for all materials are listed. The AMG must be reviewed to screen out those aging effects that are not applicable for a particular material or a particular application. The list of exceptions/clarifications and cautions in Section 5 of this appendix should be reviewed to assure consistency with the other Mechanical Tools.

Method 2: Use the Material/Environment Tables in Section 6 of This Appendix.
The tables included in Section 6 of this appendix summarize the aging effects evaluations in the AMG but are presented in a material/environment format. (These tables present the AMG results in a form that is consistent with the Mechanical Tool approach to aging effects identification.) As in Option 1, the materials of construction, specific environments and application must be identified prior to using the tables. The summary tables in Section 6 can then be used to identify the significant aging effects for the combination of materials and environments being evaluated. The exceptions/clarifications/cautions contained in Section 5 of this appendix should be reviewed and aging effects modified (if necessary) to assure consistency with the overall Mechanical Tool approach. An advantage to using this option is that the review is not limited specifically to the applications, materials and environment combinations contained in the AMG. However, there may still be some heat exchangers and or specific aging effects that cannot be completely evaluated using these summary tables. Plant specific evaluations may then be required to identify the significant aging effects.

Option 1: Use the Mechanical Tools to Identify Aging Effects

These Mechanical Tools provide a logic to identify significant aging effects for material and environment combinations. These same tools can be used to evaluate heat exchangers. However, not all materials, environments and aging effects are evaluated in the Mechanical Tools. The AMG in these cases can provide information and evaluations of some of the materials and effects not covered in the other Mechanical Tool logics. Wear and fouling of heat exchanger components are examples of mechanisms that are not included in the other Mechanical Tools. Some of the logic in the Mechanical Tools, although applicable to heat exchangers, may have to be interpreted differently. For example, pitting and crevice corrosion require stagnant or low flow conditions. In some heat exchanger applications there may be areas of low flow even system flow is high.

There may not be any single approach that deals adequately with all heat exchangers. There may also be some exceptions that will require plant specific aging effects identification since they are not covered by any of the three approaches (none of the approaches, for example, cover refrigerant lines and coils in air conditioners). However, using one or more of these approaches should provide acceptable results for most of the heat exchangers requiring aging management review.

3. AMG HEAT EXCHANGERS EVALUATED

The Sandia AMG provides evaluations of aging effects for limited applications, materials and environments. Heat exchangers falling outside these specific applications can be evaluated using information contained in the AMG, however, a more detailed approach is required and the summary tables of the AMG may be of limited use. The important criteria, as in all the aging evaluations contained in these appendices, is to determine the specific material and environment and perform the aging effects evaluation using the sources of information or tools available.

Table 3-1 summarizes the combinations of materials and environments that are considered in the AMG and are applicable to both BWRs and PWRs. The combinations of materials and environments included in the AMG comprise a majority of the plant specific heat exchangers that require aging management review under the license renewal requirements. There are likely to be many heat exchangers, however, that are not specifically included in the AMG evaluation. Table 3-1 provides a summary of the specific heat exchangers covered in the AMG. Even if a plant specific application is not included, the summary of aging effects for similar heat exchangers and/or applications (i.e., identical materials and environments on the tube and shell side) should enable most heat exchangers to be evaluated with very little, if any, additional review necessary.

The table below was prepared utilizing the information contained in the following sections of the AMG; 1) Section 3.4.5, Description of Predominant Types of Heat Exchangers; 2) Table 3-5, Process and Cooling Fluid Media BWR Heat Exchangers, and; 3) Table 3-6, Process and Cooling Fluid Media PWR Heat Exchangers. It represents all the material, environment and types of coolers that are evaluated in the AMG. This Table provides a summary and easy reference for the material and environment combinations considered in the AMG. Using this information, it is easy to discern that no heat exchangers evaluated in the AMG contain raw water on the shell side of the heat exchanger. That application is, therefore, not considered in the AMG and aging effects are not identified.

Table 3-1 Heat Exchangers Evaluated by the AMG

	MATERIAL		FLUID	
Tube/Shell	**Tube Side**	**Shell Side**	**Tube Side**	**Shell Side**
RWCU Regen. (BWR)	SS	SS	Primary	Primary
RWCU Non-Regen. (BWR)	SS	CS	Primary	Closed
Letdown Hx	SS	CS	Primary	Closed Cooling
HP Gland Seal Cond (BWR)	SS	CS	Treated	Primary
Seal Return Cooler	SS	CS	Primary	Closed Cooling
Spent Fuel Pool Cooler	SS	CS	Treated	Closed Cooling
Component Cooling Water Hx	SS, Admiralty, 90-10 /Cu-Ni, Alum-Brass	CS	Raw	Closed Cooling
Residual Heat Removal (PWR)	SS	CS or CS w/SS overlay	Primary or Borated	Closed Cooling
Residual Heat Removal (BWR)	SS	CS	Raw	Primary
Emer. Diesel Gen. Jacket Cooling	Admiralty, Copper Alloys	CS	Raw	Treated or Closed Cooling
Lube Oil (EDG, HPCI, RCIC)	Admiralty, Copper Alloys SS	CS	Treated Water or Raw Water	Lubricating Oil
Misc. Oil Coolers	Admiralty, Copper Alloys	CS	Closed Cooling	Lubricating Oil
Fin/Coil	**Coil Side**	**Open Side**	**Coil Side**	**Open Side**
Containment/ Drywell Air Coolers	Copper or 90-10 Cu-Ni	Alum., Copper, or 90-10 Cu-Ni	CCW, Service, Raw, or Chilled	Containment or Drywell Atmos.
ECCS Room Coolers	Copper or 90-10 Copper Nickel	Alum., Copper, or 90-10 Cu-Ni	Raw or Closed Cooling	Air

The fluid environments identified in the AMG differ only slightly from the environments considered in the other Mechanical Tool Appendices. The Mechanical Tools do not address PWR primary water as it is addressed specifically in a separate Reactor Coolant System AMG. The remaining water systems are categorized as either treated or raw water. The raw water category in the AMG and as used in these tools are the same. The treated water category in these Mechanical Tools includes both the treated and closed cooling water as defined in the AMG. The difference between treated and closed cooling systems as evaluated in the AMG is the addition of corrosion inhibitors and/or biocides to the closed cooling water. Both treated and closed cooling water as addressed in the AMG are considered to contain filtered and demineralized but not deaerated water. As in these Mechanical Tools, the AMG classifies the borated spent fuel pool water in PWRs as treated water.

Primary Water
Reactor coolant which has been deaerated/deoxygenated. This water may contain up to 200 ppb dissolved oxygen. Primary water in PWR plants also contains a borated solution. During refueling outages aerated primary coolant can have dissolved oxygen contents above 8 ppm when the reactor vessel head is removed for refueling. However, refueling outages are usually brief, temperatures are low, and halogen levels are still controlled to below the threshold values. No pitting or crevice corrosion has been observed in reactor internals under these conditions as a result of extended outages. Therefore crevice corrosion is not expected during refueling outages.

Treated Water
Water which has been filtered and demineralized but generally not deaerated. The water may contain up to 5 ppm dissolved oxygen and small amounts of chemicals (i.e. potassium chromate, and sodium nitrite) for process use. The spent fuel pool water in PWR plants contains 2000 to 2500 ppm boron.

Closed Cooling Water
Treated water containing corrosion inhibitors and biocides.

Lubricating Oil
Low to medium viscosity hydrocarbons used for bearing gear and engine lubrication.

Air
The air is the surrounding ambient of various rooms, containment or the drywell. Air-side filters are typically provided to remove particulates from the air stream.

Raw Water
Water entering a plant from a river, lake, pond or bay, which has not been chemically treated or demineralized. In general, the water has been rough-filtered to remove large particles and contains biocidal additives for microorganism control. The sodium chloride content in lake or river water is typically less than 1,000 mg/l, while either ocean or brackish water has a sodium chloride content of greater than 1,000 mg/l.

4. HEAT EXCHANGERS IN THE SCOPE OF LICENSE RENEWAL

The extent to which plants rely on Balance of Plant (BOP) equipment for compliance with license renewal rule requirements determines which equipment falls within the scope of license renewal. Some plants may designate very little BOP equipment as being within the license renewal scope under its CLB. Other plants may take credit for BOP equipment to meet regulated events or design basis events. For example, if the main condenser is used as a source of water to demonstrate compliance with a design basis event or a regulated event (e.g. LOCA and Appendix R), then the main condenser may require AMR.

Even where specific heat exchanger applications are addressed, the AMR can sometimes require plant specific evaluations. For example, the decay heat or residual heat removal coolers will require AMR at all plants, however, the material used for construction, the design parameters and the tube and shell side environment may differ from plant-to-plant. The conditions covered in the AMG do not include an evaluation of raw water on the shell side of the decay heat removal coolers. A plant that has raw water on the shell side would, therefore, have to perform additional evaluations to complete the identification of aging effects if using the AMG.

While evaluating heat exchangers using the Sandia AMG, the basis and assumptions must be completely understood before using the results of the aging effects evaluations. When conditions and assumptions for the heat exchanger being evaluated are an exact match with those in the AMG, the results are valid. Where the conditions and/or assumptions do not exactly match, more evaluation is necessary to assure the results.

The following list of heat exchangers identifies “typical” heat exchangers that can be identified as within the scope of license renewal. This list is not complete, but is included to emphasize the variety of heat exchangers that are expected to require aging management review. Some of these heat exchangers will be exact matches in application, material and environment to those evaluated in the AMG; others will require additional work to assure that all aging effects are identified. The list is broken down into two distinct types of heat exchangers. The shell and tube heat exchangers have fluids on both the tube and shell sides. The fin/coil type heat exchangers are used for containment or room cooling. Air flows across a baffled tube bundle in these coolers with a cooling fluid on the tube side. For these fin/coil heat exchangers there is no shell side as the tubes are open to the air flow.

Tube and Shell Type

- Residual Heat Removal Coolers
- Reactor/Seal Return Letdown Coolers (PWR)
- RWCU Regenerative and Non-Regenerative (BWR)
- Emergency Diesel Jacket Water Coolers
- Makeup Pump Coolers
- Reactor Building Spray Pump Jacket Coolers
- Residual Heat Removal Pump Jacket Coolers
- Station Blackout Diesel Heat Exchangers
- Fire Pump Coolers
- Post Accident Sampling Coolers
- Electrical Room Chiller Unit Condensers
- Reactor Coolant Pump Thermal Barriers (PWR)
- RC Drain Tank Heat Exchanger (PWR)
- Pump Lube Oil Coolers
- Main Condensers
- RCP Upper and Lower Oil Coolers (PWR)
- Generator Thrust Bearing and Guide Bearing Coolers
- Spent Fuel Coolers
- Component Cooling Water Coolers
- Service Water Coolers
- Raw Water Coolers
- Diesel Generator Standby Heaters

Fin/Coil Type

- Reactor Building Coolers
- Drywell Coolers
- Emergency Core Cooling System Room Coolers
- Control Room Coolers
- Electrical Equipment Room Coolers
- RCP Motor Air Coolers (PWR)
- Air Conditioners
- Diesel Generator Radiators

5. EXCEPTIONS/CLARIFICATIONS/CAUTIONS

1. The AMG does not distinguish between treated and closed cooling water environments. In Sections 4.3.1.5.4 and 4.3.2 of the AMG, the discussions conclude that microorganisms are present in treated and closed cooling water systems. Although the AMG describes closed cooling water as containing corrosion inhibitors and biocides, the discussions of MIC indicate that for treated or closed cooling water, the potential exists for the presence of MIC. The Mechanical Tools apply the logic that if a biocide is added to the treated water, then MIC is not a concern. It is recommended that for both treated and closed cooling water, the determination of the plausibility of MIC be based on whether or not a biocide is used.

2. The evaluations of closed water systems also do not consistently apply the addition of corrosion inhibitors. General corrosion is deemed a significant aging mechanism in closed water systems (assumed to contain corrosion inhibitors), yet the discussions for galvanic corrosion indicate that the inclusion of corrosion inhibitors limits this type of corrosion.

3. During the evaluation of aging effects in heat exchangers, consideration is often given in the AMG to common design aspects of heat exchangers such as sacrificial anodes and surface coatings to control aging. The aging evaluation takes credit for these design attributes oftentimes without qualification. It is incumbent on a utility to ensure the continued integrity of such design attributes in order to apply the conclusions drawn in the AMG.

   The AMG interpretation of thermal embrittlement and creep for the different heat exchanger materials of construction should be examined carefully. The initial screening logic temperature threshold used in the AMG for creep and thermal embrittlement for all heat exchangers is 200^{o}F. The heat exchangers exceeding this temperature threshold (letdown, excess letdown, RWCU regenerative and seal water heat exchanger) were further evaluated with stainless steel and titanium being the only materials exceeding the temperature threshold for any extended period. The subsequent evaluation concluded that titanium and stainless steel were not susceptible to creep or thermal embrittlement. The evaluation also indicated that CASS is susceptible to thermal embrittlement, but that none of the heat exchangers evaluated contained cast austenitic stainless steel.

   The conclusions drawn in the AMG (i.e. creep and thermal embrittlement are not applicable) is likely a valid conclusion based on the logic in the Mechanical Tools. To be consistent with the other Mechanical Tool Appendix, creep of metals is not a concern at PWR or BWR plant temperatures and should be eliminated from consideration for that reason. Thermal embrittlement of cast austenitic stainless steel and stainless steel welds is a concern if the equipment is operated at high temperatures. The treated water tool (Appendix A of these Mechanical Tools) uses a threshold temperature of 482^{o}F above which stainless steel is susceptible to thermal embrittlement.

4. In the AMG carbon steel is evaluated in a primary water application only for a BWR application. This evaluation should not be extrapolated to a PWR primary water environment which contains boric acid.

5. Section 4.3.1.6.1 of the AMG states, "IGSCC has been reported for stainless and high alloy steel components exposed to borated water service applications (PWR applications). Therefore, if the heat exchanger components are stainless or high alloy steel and exposed to borated fluids, then IGSCC is a significant aging mechanism." This conclusion is contrary to the mechanical treated water tool and the RCS aging evaluation. Failures attributed to IGSCC have been reported (e.g., IN 79-19), however, those failures were attributed to other contaminates such as chlorides and thiosulfate and not boric acid. The treated water tool (Appendix A) should be consulted to determine the threshold values for oxygen and contaminant levels above which SCC may be a concern.

6. The heat exchanger AMG states that mechanical fatigue is a significant aging mechanism for all heat exchanger components regardless of materials and operating history. The remainder of the Mechanical Tools treat high cycle fatigue as a plant specific phenomenon to be included as an aging effect dependent on the AMR approach employed. The Mechanical Tools were not developed to include the evaluation of heat exchangers and the AMG determinations should be followed because of the thermal stresses and cycles experienced by heat exchanger components.

7. Raw water was not evaluated as an environment on the shell side of the heat exchangers in the AMG since no such applications were identified in which that situation existed. The B&W PWR plants contain at least one heat exchanger where raw water flows on the shell side. The AMG does evaluate the various materials of interest on the shell side in a raw water environment and the tables in Section 6 of this appendix list those applicable aging effects.

8. Pitting is an aging mechanism that is only prevalent in stagnant or low flowing conditions. The AMG identifies pitting as a concern only in a raw water environment and without regard to flow conditions. Because of the design and configuration of most heat exchangers, stagnant and low flow areas likely exist even during system flow conditions. Caution should be used if attempting to rule out pitting based on flow conditions.

9. The logic as to conditions conducive to pitting and crevice corrosion contained in the Mechanical Tools differs from the AMG discussions. The Mechanical Tools assume that the necessary conditions for pitting and crevice corrosion can exist in raw, treated and closed cooling water systems. The treated water tool (Appendix A) establishes minimum contaminant (such as a halide or sulfate) and oxygen concentrations necessary for pitting and/or crevice corrosion to be a concern. The raw water tool (Appendix A) assumes that contaminants are present and does not include minimum concentrations in the aging effects logic. The AMG considers pitting and crevice corrosion to be significant only in raw water systems. The AMG considers both treated and closed cooling water not to be conducive to the

propagation of pitting or crevice corrosion. The AMG takes credit for the water quality control programs to prevent pitting and crevice corrosion in treated and closed cooling water systems.

To provide consistency with the Mechanical Tools, pitting and crevice corrosion should be evaluated in accordance with the treated water and raw water logic contained in Appendices A and B, respectively, of these Mechanical Tools.

10. The discussion in item 9 is also applicable to the AMG discussions on SCC. The AMG assumes that the treated and closed cooling system environments are not conducive to SCC. No basis for that assertion is provided and it is in disagreement with the treated water tool (Appendix A). In this treated water tool, SCC is a plausible aging mechanism for stainless steel in treated or closed water systems containing contaminants and/or oxygen concentrations above the identified thresholds.

    As in the pitting and crevice corrosion discussion in item 9, SCC should be evaluated in accordance with the treated water and raw water logic contained in Appendices A and B, respectively, of these Mechanical Tools.

11. The significance of galvanic corrosion as an aging mechanism is, in most cases, left unqualified in the AMG. The AMG states:

    Galvanic corrosion may be significant when, given a corrosive environment such as raw or treated water, two materials in close proximity are far apart on the galvanic series chart. In these situations, if sacrificial anodes or cathodic protection is not utilized, the more anodic material may experience significant galvanic corrosion."

    Galvanic corrosion, by this definition, is only considered significant for treated water and raw water systems. The AMG deems the addition of corrosion inhibitors sufficient to preclude galvanic corrosion in closed cooling water systems. The treated water Mechanical Tool does not credit the addition of corrosion inhibitors as a method of prevention for the effects of galvanic corrosion. Although corrosion inhibitors may limit the susceptibility of materials to galvanic corrosion, improper treatment can actually increase the corrosive environment and thus increase the corrosion rate (Reference 2, Page 73). To provide consistency with the other tools, the treated water tool (Appendix A) should be used for galvanic corrosion evaluations of AMG classified closed cooling water systems.

    In Table 6-5 (Section 6), galvanic corrosion of carbon and low alloy steel on the shell side of heat exchangers is identified as a significant aging mechanism. The AMG makes this assertion based on the applications where stainless steel on the primary side is matched with carbon steel on the shell side. While it may be true that under these conditions carbon or low alloy steel may be in contact with stainless steel tubes or tubesheets, construction and design practices will typically make provisions for these types of situations. Either welding materials, sacrificial anodes, or isolation devices will likely be used to prevent galvanic corrosion where dissimilar materials are in contact. The use of these design practices is included in the AMG with the distinction made that galvanic corrosion is only a significant aging mechanism if this type of design protection is not included. Sacrificial anodes are a method to prevent significant corrosion of the heat exchanger material, however, it is incumbent upon a utility to have in place a program to inspect or otherwise assure the integrity of these sacrificial anodes. If an installed sacrificial anode has been depleted or becomes unattached, it will no longer protect the component and severe corrosion may follow.

12. Oil is only evaluated on the shell side of the heat exchangers in the AMG. Since oil is usually a non-corrosive environment and flow rates for oil containing systems are typically low, the extrapolation of significant aging effects to the tubes, tubesheet and waterbox are made for oil environments. Fouling is identified as a significant aging effect for oil systems where the oil source is the bottom of a tank or reservoir. This could lead to corrosion products or contamination of the oil supply. Such contamination could also result in some forms of corrosion, however, none are found to be applicable. If the oil source is from the bottom of a reservoir or tank, the applicability of corrosion aging effects should be evaluated further.

13. Erosion-corrosion is not covered in the Mechanical Tools specifically as it applies to heat exchangers. The discussions of this aging effect as it pertains to heat exchangers are, therefore, limited to the evaluations in the AMG. Since the AMG specifically evaluates the various sub-components and environments for only those applications within the scope of the AMG, not all material, environment and applications are evaluated. (Raw water, for example, is evaluated on the tube side but not on the shell side of heat exchangers.) The materials evaluated on the tube side of heat exchangers are similar to the materials on the shell side and, with the exception of flow conditions, the susceptibility of the material to erosion-corrosion is no different. Erosion-corrosion is highly dependent on flow rate where flow rates above 3 ft/sec must exist for it to be a significant aging effect.

    The AMG includes consideration of a select group of heat exchangers and the identification of aging effects is limited to that select set. Plant specific requirements and applications will require aging management review of heat exchangers that are not included in the AMG. If using the AMG as a tool to identify aging effects for heat exchangers outside the AMG scope, all assumptions and operating conditions assumed in the AMG for the evaluation must be verified. Even where there appears to be an exact match with a heat exchanger covered in the AMG, a review of the AMG assumptions and operating conditions considered may be necessary to completely remove erosion-corrosion as a concern. The AMG specifically identifies the included heat exchanger designs, manufacturer, materials used, operating conditions assumed, etc. If a plant specific application violates any of the AMG evaluation criteria, the conclusions may no longer be valid. Statements similar to "...as long as the heat exchangers are not subjected to temperatures above..." and "most plants treat closed cooling water with corrosion inhibitors, as long as an inhibitor is used then this aging effect is not a concern." The erosion-corrosion evaluation makes similar assumptions and statements. Heat exchanger tube plugging and changes in system and equipment operation can change internal flowpaths and fluid velocities such that fluid velocities fall outside those assumed in the AMG.

Erosion-corrosion becomes a concern where previously it was not. The summary tables in Section 6 contain summary notes of the erosion-corrosion evaluations in the AMG.

14. Section 4.3.2.1.4 of the AMG erroneously makes the statement that inhibited admiralty brass contains less than 15% zinc and is not susceptible to IGSCC and/or TGSCC. Inhibited admiralty brass contains 28% zinc and is susceptible to SCC. The inhibited admiralty brass provides resistance to dezincification but not SCC.

15. The AMG lists numerous NRC Bulletins, Notices, Generic Letters, and Circulars applicable to the in scope heat exchangers. It does not include discussion of NRC Circular 80-11, “Emergency Diesel Generator Lube Oil Cooler Failures.” Specifically, pressure boundary failures that occurred as a result of severe corrosion of the tube to tubesheet solder joint in oil coolers manufactured by EMD of General Motors. This corrosion resulted from the combination of soft solder in a raw water environment and in the presence of Calgon CS, a borated-nitrite type inhibitor. Calgon CS should not be used in situations where the solder joint composition is a soft solder of lead-tin composition. Although this issue has likely been addressed at plants due to the date of the Circular, corrosion of this solder joint is a significant aging mechanism for these specific coolers under the conditions identified and should be considered during the aging evaluation.

6. SUMMARY OF RESULTS FROM HEAT EXCHANGER AMG

The Sandia Aging Management Guideline for Heat Exchangers (AMG) evaluates numerous heat exchangers that are constructed of various materials exposed to a variety of different environments. However, the AMG does not evaluate all material/ environmental combinations.

In addition to materials and environments, heat exchangers are discussed in the AMG on a sub-component basis. Because of the number of variables involved, not all combinations of materials, environments and sub-components are evaluated. The AMG limits its evaluation to those applications covered by the in-scope heat exchangers. No AMG heat exchanger applications, for example, have raw water on the shell side, therefore, this combination is not included. The evaluation of the primary water only includes stainless steel and titanium (carbon steel is evaluated only for a very specific and limited duration situation in BWRs).

Although not all combinations of materials, environments and sub-components are evaluated, as is shown in Table 5-1, most of the material/environments combinations are evaluated. The results of the material/environment evaluations for the covered sub-components are easily extrapolated to the other sub-components (for example, the significant aging effects using raw water on the shell side of heat exchangers have been extrapolated using information contained in the AMG). Where results are component or system condition specific (such as erosion-corrosion), additional work may be required to complete the aging effects identification.

Table 6-1 Materials/Fluid Combinations Evaluated in AMG

MATERIAL	Primary Water	Treated Water	Closed Cooling Water	Raw Water	Lube Oil	Containment Atmosphere
Stainless Steel and High Alloy Steel	X	X	X	X	X	X
Carbon and Low Alloy Steel	X	X	X	X	X	X
Copper, Cu-Ni Alloys, Muntz Metal		X	X	X	X	X
Inhibited Admiralty Brass		X	X	X	X	X
Titanium	X	X	X	X	X	X
Aluminum						X

The AMG evaluation of aging effects provides an in depth evaluation of a significant number of heat exchangers within the scope of license renewal. The specific heat exchangers evaluated are identified in Section 3 of this Appendix. The methodology and approach used in the AMG is to first evaluate the many aging mechanisms for the environments and materials within the scope of the AMG. An initial screening of the aging mechanisms is performed which provides a determination of susceptibility of the heat exchanger sub-components to these aging mechanisms. A detailed aging effects evaluation is then completed for the sub-components to identify the "significant" aging mechanisms for the materials and sub-components.

The results of the aging mechanism evaluations are tabulated in the AMG Tables 4-3 through 4-8. These tables summarize the significant aging effects that are applicable to the heat exchanger sub-components, each table representing a specific environment. Because of the many materials used throughout the heat exchangers, applying these tables to a specific heat exchanger is difficult at best. Since heat exchangers typically include two distinct environments, two tables are required. These tables summarize the significant aging mechanisms for a particular sub-component and, since many materials are evaluated, not all identified aging effects may be applicable to the specific application being evaluated. AMG table 4-4 for treated water systems is an example of a situation in which both stainless and carbon steel tubesheets are evaluated. This table indicates that in a treated water environment general corrosion and stress corrosion cracking are both significant aging mechanisms for tubesheets. This table does not indicate that general corrosion is only significant for carbon steel and not for stainless steel, while stress corrosion cracking is only significant for stainless steel and not carbon steel.

Although some exceptions do exist, the significant aging mechanisms identified are material and environment specific. The detailed review of the AMG evaluation and summary of aging effects supports this assertion. For example, general corrosion is a significant aging mechanism for carbon steel in treated water but the material location within the heat exchanger is not relevant. Galvanic corrosion, however, may be dependent on the particular sub-component design, since the susceptibility to galvanic corrosion is based on contact with different materials.

The tables below represent a summary of the AMG aging mechanism evaluation from a materials and environment perspective. Where exceptions to the AMG are taken to provide consistency with these Mechanical Tools, appropriate notes are included. Any sub-component specific information is included as notes to these tables. Any conditions not following a typical material/environment evaluation are also noted. Each table represents a specific environment, with significant aging effects identified for the materials evaluated in the AMG.

Table 6-2 Significant Aging Effects for a Primary Water Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless Steel			X					X		X	X
Carbon Steel			X						X	X	X
Titanium			X							X	X

Notes:

1. Thermal embrittlement and creep are discussed in Section 5, item No. 2.

2. Stainless Steel is used for all PWR applications in a primary water environment. Carbon steel in a primary water environment only applies to BWR Residual Heat Removal (RHR) and Gland Seal heat exchangers (the RHR heat exchanger can contain either treated or primary water). The other BWR heat exchangers utilize stainless steel for primary water applications.

3. Stress Corrosion Cracking is discussed in Section 5, item No. 5. This is applicable only to BWR primary water applications. PWR primary water (containing borated fluid) does not result in susceptibility of stainless steel to SCC unless other contaminants are present. This is an exception to the AMG.

4. Erosion-Corrosion. Primary water is fine filtered to remove particulate and de-ionized to achieve purity. It also contains corrosion inhibitors to minimize abrasive corrosion products. Dissolved oxygen levels in primary water applications are controlled to minimize accumulation of abrasive corrosion products. As long as the water chemistry is controlled and fluid velocities are maintained within specified limits, erosion/corrosion for most heat exchanger components is not a significant aging mechanism. Exceptions are the shell/nozzles/internals components. Normally the shell/nozzles/internals components are constructed of stainless steel in high velocity applications, however, if they are constructed of carbon steel (as in the BWR RHR and Gland Seal condenser) and are exposed to fluid velocities greater than 6 ft/sec then erosion-corrosion is a significant aging mechanism. This minimum threshold velocity is in agreement with the raw water tool (Appendix A). Erosion-corrosion is a localized effect, occurring where the local velocity is high enough to remove the oxidation coating on the internal surface. Specifically in a heat exchanger, the flow distribution is such that locally high velocities can exist under "normal" flowing conditions. The application of an "average" flow velocity may lead to a non-conservative conclusion that erosion-corrosion is not a concern.

5. Wear is identified as a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.

Table 6-3 Significant Aging Effects for a Treated Water Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless and high alloy steel			X				X			X	X
Carbon and low alloy steel			X	X		X	X		X	X	X
Cu, Cu-alloys Muntz metal			X	See Note 2			X	See Note 5	X	X	X
Inhibited Adm. Brass			X				X	X	X	X	X
Titanium			X				X			X	X

Notes:

1. Thermal embrittlement and creep are discussed in Section 5, Item No. 2.

2. Muntz metal (and other copper alloys with greater than 15% zinc) are susceptible to selective leaching (dezincification) in a treated water environment. Inhibited admiralty brass provides resistance to dezincification based on 1% tin content.

3. Galvanic corrosion is discussed in Section 5, Item No. 11. Raw water on the shell side is not specifically addressed in the AMG since no heat exchangers in the scope of the AMG contain raw water on the shell side. We have identified at least one application in which Raw water flows through the shell side of the RHR heat exchangers. The treated water evaluations indicate that galvanic corrosion is a significant aging mechanism for shell/nozzle/internals and waterbox/channel head/divider plate subcomponents where materials used are not close together on the galvanic chart and where sacrificial anodes or cathodic protection is not provided. This same logic would apply to a raw water environment.

4. MIC can attack any material but is only a significant aging mechanism for treated water systems if a biocide is not used.

5. Stress Corrosion Cracking is a significant aging mechanism for copper alloys with greater than 15% zinc content. Muntz metal contains approximately 40% zinc.

6. Erosion-Corrosion. Treated water applications contain fine corrosion products that will collect at the bottom of tanks and reservoirs. These particles are highly abrasive and can be pumped into the various heat exchanger components. Treated water also is considered to be a corrosive fluid owing to its high oxygen content.

<u>Tubes</u>	Treated water on the shell side was only evaluated for stainless steel with no significant effect identified. Treated water on tube inside surfaces was evaluated. If tubes are made from copper nickel alloys or admiralty brass, erosion/corrosion is a significant aging mechanism based on high dissolved oxygen and potential particulate content.
<u>Tubesheet.</u>	If tubesheet is made from Muntz metal or carbon steel, erosion-corrosion is a significant aging mechanism.
<u>Shell</u>	Only the BWR RHR cooler is evaluated for shell side treated water. Erosion-Corrosion is not significant because operation is only intermittent in that mode. However, the AMG in at least one place also lists HPCI gland seal condenser with shell side treated water. The same logic of intermittent operation should also apply to that heat exchanger.
<u>Waterbox</u>	If waterbox components are made from carbon steel, erosion-corrosion is a significant aging mechanism.

7. Wear is a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.

8. In treated water applications corrosion product particulates can accumulate at the bottom of tanks or reservoirs. Fouling is a significant aging mechanism where the water supply originates at the bottom of a tank or reservoir.

Table 6-4 Significant Aging Effects for a Closed Cooling Water Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless and high alloy steel			X				X			X	
Carbon and low alloy steel			X	X			X		X	X	
Cu, Cu-alloys Muntz metal			X	See Note 2			X	Note 5		X	
1. Inhibited Adm. Brass			X				X	X		X	
Titanium			X				X			X	

Notes:

1. Thermal embrittlement and creep are discussed in Section 5, Item No. 2.
2. Muntz metal (and other copper alloys with greater than 15% zinc) are susceptible to selective leaching (dezincification) in a closed cooling water environment. (Inhibited admiralty brass is not susceptible due to 1% tin content which hinders deposition of copper.
3. Corrosion inhibitors are added to closed cooling systems. The AMG credits the addition of corrosion inhibitors as a means to minimize galvanic corrosion effects.
4. MIC is a significant aging mechanism for closed cooling water systems if a biocide is not used
5. Stress Corrosion Cracking is a significant aging mechanism for copper alloys with greater than 15% zinc content. Muntz metal contains approximately 40% zinc.

6. Erosion-Corrosion. Closed cooling water is fine filtered to remove particulate and deionized to achieve purity. It also contains corrosion inhibitors to minimize abrasive corrosion products. As long as the water chemistry is controlled and fluid velocities are maintained within specified limits, erosion corrosion for most heat exchanger components is not a significant aging mechanism. One exception is the shell/nozzles/internals components. Normally the shell/nozzles/internals components are constructed of stainless steel in high velocity applications, however, if they are constructed of carbon steel and are exposed to fluid velocities greater than 6 ft/sec then erosion-corrosion is a significant aging mechanism (see Table 6-2, note 4)

7. Wear is a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.

Table 6-5 Significant Aging Effects for a Raw Water Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless and high alloy steel			X		X		X	X		X	X
Carbon and low alloy steel			X	X	X	X	X		X	X	X
Cu, Cu-alloys Muntz metal			X	X	X	X	X	X	X	X	X
Inhibited Adm. Brass			X	X	X	X	X	X	X	X	X
Titanium			X				X			X	X

Notes:

1. Thermal embrittlement and creep are discussed in Section 5, Item No. 2.

2. General corrosion of copper nickel or inhibited admiralty tubes is a significant aging mechanism if operation of the heat exchanger is cyclic. General corrosion of carbon and low alloy steel in a raw water environment is a significant aging mechanism. Although raw water was not evaluated on the shell side of heat exchangers, various other components (e.g. tubesheet, waterbox) are evaluated in this environment. General corrosion in the form of selective leaching (dezincification) of muntz metal tube sheets is a significant aging mechanism.

3. Pitting is a significant aging mechanism for all materials with the exception of titanium. Pitting is not a concern for titanium or its alloys. The susceptibility to pitting is dependent on contaminants, oxygen and fluid velocity. Section 4.3.2.1.3 of the AMG contains threshold velocities for several materials. Due to the cyclic operating nature of many heat exchangers and the complex fluid flow paths, it is likely that all heat exchangers will experience flow rates below these threshold values at various locations even under full flow conditions.

4. The AMG credits good design practices with preventing the occurrence of galvanic corrosion for the tubes and tubesheet material. Where necessary, sacrificial anodes or cathodic protection are utilized and galvanic corrosion is not a concern. Raw water on the shell side is not specifically addressed in the AMG since no heat exchangers in the scope of the AMG contain raw water on the shell side. There is at least one application where raw water flows through the shell side of the RHR heat exchangers. The treated water evaluations indicate that galvanic corrosion is a significant aging mechanism for shell/nozzle/internals and waterbox/channel head/divider plate subcomponents where materials used

are not close together on the galvanic chart and where sacrificial anodes or cathodic protection is not provided. This same logic applies to a raw water environment.

5. Microbiologically induced corrosion is a significant aging mechanism for all materials in a raw water environment. Plant specific use of biocides to prevent MIC is performed at some plants. This would reduce the susceptibility to MIC damage.

6. Stress corrosion cracking is a significant aging mechanism for stainless steel and copper alloys containing greater than 15% zinc. Muntz metal (40% zinc) and inhibited admiralty brass (28% zinc) are susceptible to SCC.

7. Erosion-Corrosion
   Raw water applications contain fine particles such as sand and silt that pass through the rough screens. These particles are highly abrasive and raw water is considered to be a corrosive fluid. Erosion-Corrosion of many heat exchanger materials in this environment is a significant aging mechanism.

   The AMG identified no application in which raw water was on the shell side of the heat exchangers. Although not specifically evaluated, the susceptibility of the shell side erosion-corrosion can be extrapolated using the tube, tubesheet, and waterbox evaluations.

<u>Tubes.</u>	Admiralty brass and copper nickel alloys are susceptible to erosion-corrosion.
<u>Tubesheet.</u>	Carbon steel and Muntz metal are susceptible to erosion-corrosion.
<u>Shell/Nozzle/Internals</u>	Carbon/low alloy steel are susceptible
<u>Waterbox/Channel Head/Divider Plate</u>	Carbon/low alloy steel are susceptible

8. Wear is a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.

Table 6-6 Significant Aging Effects for a Lubricating Oil Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless and high alloy steel			X							X	X
Carbon and low alloy steel			X							X	X
Cu, Cu-alloys Muntz metal			X							X	X
Inhibited Adm. Brass			X							X	X
Titanium			X							X	X

Notes:

1. All heat exchangers evaluated operate with oil on the shell side. The AMG bases aging effects identification on strict controls for the quality and purity of the lubricating oil and the fact that they are regularly checked. The AMG assumes that very little corrosion occurs in lubricating oil systems because oxygen content is low, oils are not good electrolytes and purification systems are generally installed and/or corrosion inhibitors added to maintain the oil free of corrosion products.

2. Thermal embrittlement and creep are discussed in Section 5, Item No. 2.

3. Mechanical fatigue is assumed for all materials and all environments in heat exchanger applications.

4. Galvanic corrosion is not a significant aging mechanism. According to the AMG even contaminated condition oils are not good electrolytes.

5. MIC is not a significant aging mechanism. AMG basis is that even in the contaminated condition, oils do not support microorganism growth. This is contradictory to the oil/fuel oil tool (Appendix C) which assumes that contaminated oil may contain moisture and microorganisms.

6. SCC is not a significant aging mechanism. AMG basis is that the operating environment and temperatures do not support the mechanisms. This is also contradictory to the oil tool logic which assumes that moisture may be present and could initiate SCC.

7. Erosion-corrosion is not a significant aging mechanism. Erosion-corrosion occurs when the base material is susceptible to general corrosion in fluid environments. This is not the case with an oil environment.

8. Wear is a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.

9. Fouling is a significant aging mechanism in oil applications where the source of oil is the bottom of a tank or reservoir and, therefore, could result in the carryover of particulate matter. All oil applications in the AMG have the lubricating oil on the shell side of the heat exchanger. The shell material is carbon or low alloy steel while the tube material may consist of any of the materials listed in the table (except carbon and low alloy steel).

Table 6-7 Significant Aging Effects for an Air Environment

MATERIALS	Thermal Embrit.	Creep	Mech. Fatigue	General Cor.	Pitting Cor.	Galvanic Cor.	MIC	SCC	Erosion - Cor.	Wear	Fouling
Stainless and high alloy steel			X							X	X
Cu, Cu-alloys Muntz metal			X							X	X
Inhibited Adm. Brass			X						X	X	X
Titanium			X							X	X
Aluminum			X							X	X

Notes:

1. Thermal embrittlement and creep are discussed in Section 5. Item No. 2
2. Air coolers evaluated are all open coil/fin type coolers. Therefore, no tube side or shell side considerations are made.
3. Mechanical fatigue is assumed for all materials and all environments in heat exchanger applications.
4. Erosion-corrosion of inhibited admiralty brass tubes is a significant aging mechanism if the water vapor is acidic and the air flow frequently changes direction.
5. Wear is a significant aging mechanism for all tube and tubesheet materials and in all environments within the scope of the AMG.
6. Materials for the tube side and exterior tubesheet were not well defined in the AMG for all the air coolers. As a result, corrosive effects on the tubes, tube baffles and exterior of the tube sheets may not be adequately evaluated.
7. Fouling of the air side can occur from the accumulation and build up of dust, dirt and debris on and between the fins of open coil/fin type coolers.

7. CERTIFICATION

This appendix is an accurate and appropriate for using the “Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers” by the B&W Owners Group Generic License Renewal Program.

8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate and appropriate for its intended function.

8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

8/14/99

David J. Firth Date
GLRP Project Manager

8. REFERENCES

1. Sandia National Laboratories, "Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers," Contractor Report No. SAND93-7070, June 1994.

2. M. G. Fontana, Corrosion Engineering, Third Edition, Copyright 1986, McGraw Hill.

Appendix H
Non-Class 1 Fatigue Screening Criteria

The non-Class 1 fatigue screening document provides a methodology for identifying components that may be susceptible to cracking owing to fatigue. Cracking due to other aging mechanisms may be assessed using the material and environment based tools presented in Appendices A through E. Fatigue of bolting materials is not addressed in this tool but is treated separately in the Bolted Closure Tool in Appendix F. This document may be applied when evaluating susceptibility to fatigue cracking of the following components: pipe, tubing, fittings, tanks, vessels, heat exchangers, valve bodies and bonnets, pump casings, bellows, and miscellaneous process components.

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1. INTRODUCTION

The non-Class 1 fatigue screening document (here after the Fatigue Tool) provides a logic and methodology by which systems within the scope of license renewal may be evaluated to determine locations susceptible to fatigue cracking. Cracking due to other aging mechanisms may be assessed using the material and environment based tools presented in Appendices A through E. Fatigue of bolting materials is not addressed in this tool but is treated separately in the Bolted Closure Tool in Appendix F. The Fatigue Tool may be applied when evaluating susceptibility to fatigue cracking of the following components: pipe, tubing, fittings, tanks, vessels, heat exchangers, valve bodies and bonnets, pump casings, and miscellaneous process components.

Fatigue failures in mechanical piping and components are sometimes categorized as either low cycle (typically less than 10,000 cycles) or high cycle (typically millions of cycles). Low cycle fatigue failure might occur after fewer than 10,000 cycles but only if strains exceed the yield strain. High cycle fatigue failure might occur at strains below the yield strain but only after many cycles. High cycle fatigue concerns are generally associated with high speed rotating or reciprocating equipment, vibration, or local thermal cycling due to hot and cold fluid mixing--i.e., thermal striping. Most nuclear power plant *design* fatigue applications reside within the low cycle regime.

A review of operating plant performance history [Volume 2 of Reference 1] reveals three general classifications of fatigue issues that have been observed in operating plants: vibrational fatigue failures, thermal fatigue failures, and plant license/design basis concerns. Vibrational fatigue is not considered in the Fatigue Tool since failures due to vibration are typically detected early in component service life [1] and actions are taken to prevent recurrence. Cracking due to vibrational fatigue is not an applicable aging effect for the period of extended operation. For standby systems subject to periodic testing, such as HPCI, failure caused by high cycle fatigue may be a longer term issue. Evaluation of high cycle fatigue for infrequently used systems is not addressed in this appendix and should be considered on a case-by-case basis by the user of this document.

Cracking due to thermal fatigue is considered in the Fatigue Tool. Thermal fatigue is attributed to thermal stresses that occur whenever expansion or contraction that result from heating or cooling of a body is prevented; the constraints that prevent expansion or contraction can be either externally imposed or self-imposed due to the configuration of the body and the temperature distribution. Locations that are susceptible to cracking due to thermal fatigue must be identified in accordance with the requirements of 10 CFR 54.21 (a)(3) for components within the scope of license renewal.

Plant license/design basis fatigue concerns address the design requirements associated with the components in question. For example, ANSI B31.1, ANSI B31.7 and ASME Section III include design requirements to prevent fatigue failures of piping and components. Specific editions of these Codes are part of the Current Licensing Basis (CLB) for each nuclear plant. For License Renewal, it is necessary to demonstrate that the piping and components comply with the fatigue requirements of these codes considering the stress cycles through the period of extended operation in accordance with 10 CFR 54.21 (c).

The non-Class 1 scope is large and the majority of the scope is not subject to significant cyclic thermal loading. The purpose of this document is to provide guidelines (screening criteria) for reviewing the non-Class 1 scope to identify the small subset which should be evaluated in more detail. Piping and components in this subset will either be shown acceptable by analysis, will be included in an augmented inspection program, or will be repaired or replaced. The scope of components covered by the Fatigue Tool, including materials and environments, is discussed in Section 2.0. The susceptibility of various components to thermal fatigue is discussed in Section 3.0. The development of the screening criteria to be applied to the components within the scope of license renewal is presented in Section 4.0.

2. SCOPE, MATERIAL AND ENVIRONMENTS

The scope of components covered in the Fatigue Tool is discussed in Section 2.1. Materials of construction and operating environments that apply to the components within this scope are summarized in Sections 2.2 and 2.3, respectively.

2.1.1 Scope

This document is intended for application to the following non-Class 1 components: pipe, tubing, fittings, tanks, vessels (except containment vessels), heat exchangers, valve bodies and bonnets, pump casings, bellows type expansion joints, miscellaneous process components, and other components that received fatigue evaluations in accordance with NRC requirements (e.g., BWR torus attached piping). The component evaluation boundary is consistent with the evaluation boundaries for the following design codes: ASME III (NC and ND), B 31.7 Class II and III, ASME VIII (Division 1 and 2), and B31.10. Tanks and vessels designed in accordance with TEMA and API are not within the scope of this appendix.

2.2 Materials

The materials that may be evaluated with the Fatigue Tool include carbon, low alloy, and high tensile steels, austenitic steels, nickel-chromium-iron alloy, nickel-iron-chromium alloy, and nickel-copper alloy steels. These materials should be evaluated for metal temperatures as designated by the Code of Record in the current licensing basis or the original design.

2.3 Environments

These reviews are also limited to piping and components in environments defined in Appendices A through E. However, piping and components subjected to thermal stresses in corrosive environments are not addressed in this tool and require case-by-case evaluation. A corrosive environment, with regard to fatigue evaluation, is defined as an environment that leads to material loss. If loss of material is caused by the environments covered by this tool, then further evaluation is required to assess the impact of the loss of wall thickness caused by aging mechanisms during the license renewal period. For example, the use of this tool is non-conservative when assessing fatigue damage if the component being evaluated is subjected to thermal cycles and is also susceptible to general corrosion or pitting corrosion.

3. AGING EFFECT-CRACKING

Non-Class 1 piping and components that require further evaluation of thermal fatigue to demonstrate suitability for license renewal will be identified through reviews for the following:

a) Compliance to Design Requirements

Non-Class 1 piping and components will be reviewed to determine if thermal fatigue design requirements in ANSI B31.1, ASME III and ASME VIII are met considering additional thermal cycles due to extended operation. Thermal expansion stress (S_e) is included in this evaluation because the value of S_e must not exceed the alternating stress (S_a) which is a function of the stress range reduction factor. Local strain is considered in the calculation of S_e and is not a function of time.

b) Unanticipated Thermal Fatigue

NRC bulletins and information notices were reviewed to identify non-Class 1 piping and components which may have experienced unanticipated thermal fatigue.

3.1 Compliance to Design Requirements

As discussed in Section 1.0, compliance to code design requirements for the period of extended operation must be demonstrated in accordance with 10 CFR 54.21 (c). A review of design codes applicable to the non-Class 1 scope was performed. The results of the review were used to prepare the criteria discussed in Sections 3.1.1 and 3.1.2.

3.1.1 Piping and In-Line Components

Most non-Class 1 piping and in-line components (i.e., fittings and valves) are designed in accordance with ANSI B31.1 or ASME III Subsections NC and ND. Under these Codes, secondary stresses (i.e., stress due to thermal expansion and anchor movements) are evaluated for fatigue using Stress Intensification Factors (SIFs) and stress range allowables. The early SIFs and allowables are based for the most part on the Mark l fatigue tests. Later SIFs are based on experimental and analytical studies and the relationship between the SIF and the ASME III Class 1 stress indices for moment loading (C2 and K2). The allowable secondary stress range is 1.0 S_A for 7000 cycles or less and is reduced in steps to 0.5 S_A for greater than 100,000 cycles. No increase is allowed for less than 7000 cycles. Typical stress range reduction factors are shown on the following table:

Evaluation of localized peak stresses due to thermal transients is not required by ANSI B31.1 or ASME III NC/ND. The basis for not requiring evaluation of peak stresses is that adequate protection against fatigue is provided by the rules existing in the Code for design conditions. Also, thermal transients are generally less severe for non-Class 1 piping.

Table 3-1 Stress Range Reduction Factors

Number of Equivalent Full Temperature Cycles	
N	***f***
7,000 and less	1.0
7,000 to 14,000	0.9
14,000 to 22,000	0.8
22,000 to 45,000	0.7
45,000 to 100,000	0.6
100,000 and over	0.5

Primary stresses in non-Class 1 piping due to earthquake, fluid transients and other cyclic primary loads are evaluated against conservative stress limits designed to prevent ductile failure but are not specifically evaluated as a contributor to fatigue. Again, this is due to conservatism in the Code for design conditions, and also due to the very small number of stress cycles postulated for earthquakes and fluid transients.

High cycle fatigue is not a concern for license renewal since it would be discovered during the current license period in most cases where systems are frequently operated. For standby systems subject to periodic testing, such as HPCI, failure caused by high cycle fatigue may a longer term issue. Evaluation of high cycle fatigue for infrequently used systems is not addressed and should be considered on a case-by-case basis by the user of this document.

3.1.2 Pressure Vessels, Heat Exchangers, Storage Tanks and Pumps

Non-Class 1 pressure vessels, heat exchangers, storage tanks and pumps are designed in accordance with ASME VIII or ASME III Subsection NC or ND (i.e., Class 2 or 3)[1]. Some tanks and pumps are designed to other industry Codes and standards such as American Water Works Association (AWWA) standards and Manufacturer's Standardization Society (MSS) standards. Only ASME Section VIII Division 2 and ASME Section III Subsection NC-3200 include fatigue design requirements. Conservatism in ASME Section VIII Division 1 and ASME Section III NC-3100/ND-3000 compensates for excluding requirements for detailed fatigue analysis. Also, it is expected that the component designer would have specified ASME Section VIII Division 2 or NC-3200 if cyclic loading and fatigue usage could be significant.

Both ASME Section VIII Division 2 and ASME Section III NC-3200 include provisions for "exemption from fatigue", which is actually a simplified fatigue evaluation based on materials, configuration, temperature and cycles.

Fatigue analysis is not required for ASME Section VIII Division I, Section III NC-3100 or ND vessels. It is also not required for NC/ND pumps and storage tanks (< 15 psig). The applicable

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[1] ASME III Subsection NC applies to Class 2 piping and components. Class 2 was designated Class B in early Codes. ASME Subsection ND applies to Class 3 piping and components. Class 3 was designated Class C in early Codes.

design Code for each component is noted in the component Code Data Report, Design Specification and Stress Report. It is also noted on the nameplate attached to each component.

3.2 Unanticipated Thermal Fatigue

Actual fatigue failures encountered in piping and components have not arisen because of inadequacies in design methodology, but because unanticipated thermal fatigue loads were present that were not accounted for in the original design. In particular, thermal stratification, cycling and striping in feedwater piping have resulted in numerous instances of pipe cracking due to fatigue. A search of NRC bulletins and notices to find issues related to thermal stratification in the feedwater/auxiliary feedwater piping and piping connected to the RCS has been performed. The results of this search are summarized below.

Cracking in feedwater system piping was addressed under IE Bulletin 79-13. Licensees with CE and Westinghouse steam generators reported crack indications in 16" feedwater elbows adjacent to steam generator nozzle elbow welds. No indications of cracking were found in B&W units. The NRC requested all PWR facilities to conduct examinations during the first refueling outage. Of the 54 PWRs facilities that were required to respond, cracks were found and corrected at 18 of them. It was recommended that licensees continue to perform inspections to detect possible future degradation in feedwater piping.

Thermal stresses in piping connected to reactor coolant systems were addressed under IE Bulletin 88-08. Leaks due to cracked welds in unisolable sections of piping connected to the RCS primary piping occurred at Farley 2, Tihange 1 (Belgium) and Genkai (Japan). As a result, the NRC requested licensees to review systems connected to the RCS and provide assurance that unisolable sections of piping will not be subjected to combined cyclic and static thermal and other stresses that could cause fatigue failure during the life of the plant. This is a TLAA issue for Class 1 components and will be addressed on a plant-specific basis.

Information Notice 84-87 notified power reactor facilities of damage to a feedwater system due to piping thermal deflection from stratified flow. At WNP feedwater pipe hangers and snubbers were damaged and a flange loosened allowing a small leak. This event was attributed to thermal stratification during unit startup. The NRC requested licensees to consider actions to avoid similar problems.

Information Notice 88-01 alerts addressees to a potentially generic problem concerning the reliability of piping in safety-related systems because of valve leakage that resulted in thermal cycling of the piping. On December 9, 1987, while restarting Farley Unit 2 after a refueling outage, the licensee noted increased moisture and radioactivity within containment. The unidentified leak rate for the RCS was determined to be 0.7 gpm. By ultrasonic testing, the licensee found an indication of a crack on the interior surface of the 6-inch ECCS piping connected to the cold leg of RCS Loop B. The indication was located at a weld connecting an elbow and a horizontal spool. Further, the indication was on the underside of the pipe and extended circumferentially 60 degrees in both directions from the bottom of the pipe. The crack extended through the wall for approximately 1 inch at the center of the indication. Visual and metallographic examinations showed that the weld had failed as a result of fatigue after roughly one million stress cycles. The stress loads were thermal, and the problem was corrected by directing the valve leakage away from the ECCS manifold.

Information Notice 89-80 identifies the potential or water hammer, thermal stratification, and steam binding in high pressure coolant injection piping resulting from failure of high-pressure coolant injection (HPCI) valves in boiling-water reactors (BWRs) during operation of the reactor at power. On February 21, 1989, with Dresden Unit 2 operating at power, temperature was greater than normal in the HPCI pump and turbine room. The abnormal heat load was caused by feedwater leaking through uninsulated HPCI piping to the condensate storage tank. During power operation, feedwater temperature is less than 350F, and feedwater pressure is approximately 1025 psi. Normally, leakage to the condensate storage tank is prevented by the injection check valve, the injection valve, or the discharge valve on the auxiliary cooling water pump. On October 23, 1989, with the reactor at power, leakage had increased sufficiently to raise the temperature between the injection valve and the HPCI pump discharge valve to 275 F and at the discharge of the HPCI pump to 246 F. Pressure in the HPCI piping was 47 psia. On the basis of the temperature gradient and the pressure in the piping, the licensee concluded that feedwater leaking through the injection valve was flashing and displacing some of the water in the piping with steam. The event at Dresden is significant because the potential existed for water hammer or thermal stratification to cause failure of the HPCI piping and for steam binding to cause failure of the HPCI pump.

Information Notice 91-19 was prepared to alert plants to the degradation that was possible in the feedwater system piping due to thermal stress, cracking, erosion and corrosion.

Information Notice 91-28 notified addressees of the issuance of NUREG/CR-5285 that documented the close-out of the Bulletin 79-13 responses for the 54 PWRs that were required to respond. The report recommended that licensees continue to perform inspections to detect possible degradation in feedwater piping.

Information Notice 91-38 identified concerns with thermal stratification in feedwater system piping and the resulting unacceptable pipe movement. At Beaver Valley 1 global stratification occurred over a long stretch of horizontal feedwater piping inside the containment. Instrumentation detected top to bottom temperature differentials as much as 200^{o}F. The horizontal section is preceded by a 20´ vertical section that did not provide adequate mixing to prevent stratification. It was concluded that the vertical sections offer little (if any) protection from stratification. The NRC requested licensees to consider actions to avoid similar problems.

Summary

It is concluded that unanticipated thermal fatigue is managed by plant-specific actions resulting from IE Bulletins 79-13 and 88-08, and the heightened awareness to this issue due to the aforementioned Information Notices.

4. FLOW CHART DEVELOPMENT

Screening criteria for addressing non-Class 1 components may be addressed within the following two component groups: (1) piping and in-line components, and (2) pressure vessels, heat exchangers, storage tanks, and pumps.

4.1 Screening Criteria for Piping and In-Line Components

Screening criteria for piping and in-line components are depicted on Figure 1. Screening consists of system and component level reviews.

4.1.1 System Level

The first step in system level screening is to identify piping which may have Normal/Upset Condition operating temperature in excess of 220 °F for carbon steel or 270 °F for austenitic stainless steel. These values are based on recommendations in the EPRI Fatigue Management Handbook, Volume 2, Section 4.2 (Reference 1).

The second system level step is to determine if the equivalent full temperature cycles[1] considering the period of extended operation are below the limit used for original design (usually 7000 cycles). Evaluation of individual pipe stress calculations is required if the cycle limit is exceeded during extended life.

4.1.2 Component Level

If the equivalent full temperature cycles[1] considering extended operation exceed the limit used for original design (usually 7000 cycles), evaluation of individual pipe stress calculations are required to confirm qualification. The Stress Range Reduction Factor, "f", should be applied to reduce the allowable stress. If calculated stress levels are below the reduced allowable, suitability for extended operation is demonstrated. If not, further evaluation is required.

4.2 Screening Criteria for Pressure Vessels, Heat Exchangers, Storage Tanks, and Pumps

Screening criteria for pressure vessels, heat exchangers, storage tanks and pumps are depicted in Figure 2. The first step is to identify components which may have Normal/Upset Condition operating temperature in excess of 220 °F for carbon steel or 270 °F for austenitic stainless steel. This prescreening will eliminate components from further fatigue review based on a temperature criteria. In the second step, the screening criteria is dependent upon the applicable design requirements. Code Data Reports, Design Specification, Stress Reports, component nameplates or contract files will indicate whether the Pressure Vessel, Storage Tank or Pump is designed and

[1] **Equivalent full temperature cycles are generally much less than total cycles considering small temperature changes. Equivalent full temperature cycles may be computed in accordance with ANSI B31.1, section 102.3.2 or ASME III NC 3611.2.**

fabricated in accordance with ASME VIII Division 1 or Division 2, ASME III NC or ND (i.e. , Class 2 or 3) or other Codes/Standards requirements.

4.2.1 ASME Section VIII

Under ASME Section VIII, only Division 2 vessels require evaluation for thermal fatigue (i.e., design requirements—see Section 3.1). Most non-Class 1 Pressure Vessels are designed and fabricated according to ASME VIII Division 1 requirements and are suitable for the period of extended operation without further evaluation.

If Section VIII Division 2 vessels were specified, the Design Specification and/or Stress Report should be reviewed to determine the number of stress cycles assumed for design. If the number of stress cycles considering the period of extended operation is below the number used for design, the component is suitable for the period of extended operation without further evaluation. If "exemption from fatigue" criteria were used, the basis for the exemption (i.e., number of cycles) should be reviewed to confirm that the exemption remains valid for the period of extended operation.

4.2.2 ASME Section III

Under ASME Section III, only Class 2 Pressure Vessels and Heat Exchangers designed in accordance with NC-3200 require evaluation for thermal fatigue (see Section 3.1). Fatigue evaluation is not required for ASME III Class 2 and 3 Pumps, Class 2 and 3 Storage Tanks (< 15 psig) or Class 3 Pressure Vessels.

If Class 2 Pressure Vessels and Heat Exchangers are specified, the Design Specification should be reviewed to determine if evaluation for fatigue was required (i.e., if NC-3200 design requirements were specified). If so, the Design Specification and/or Stress Report should be reviewed to determine the number of stress cycles assumed for design. If the number of stress cycles considering extended life is below the number used for design, the component is suitable for life extension without further evaluation. If "exemption from fatigue" criteria were used, the basis for the exemption (i.e., number of cycles) should be reviewed to confirm that the exemption remains valid for extended life.

4.2.3 Other Codes and Standards

Under AWWA and MSS standards, fatigue evaluation is not required for pumps and storage tanks.

4.2.4 Screening Criteria

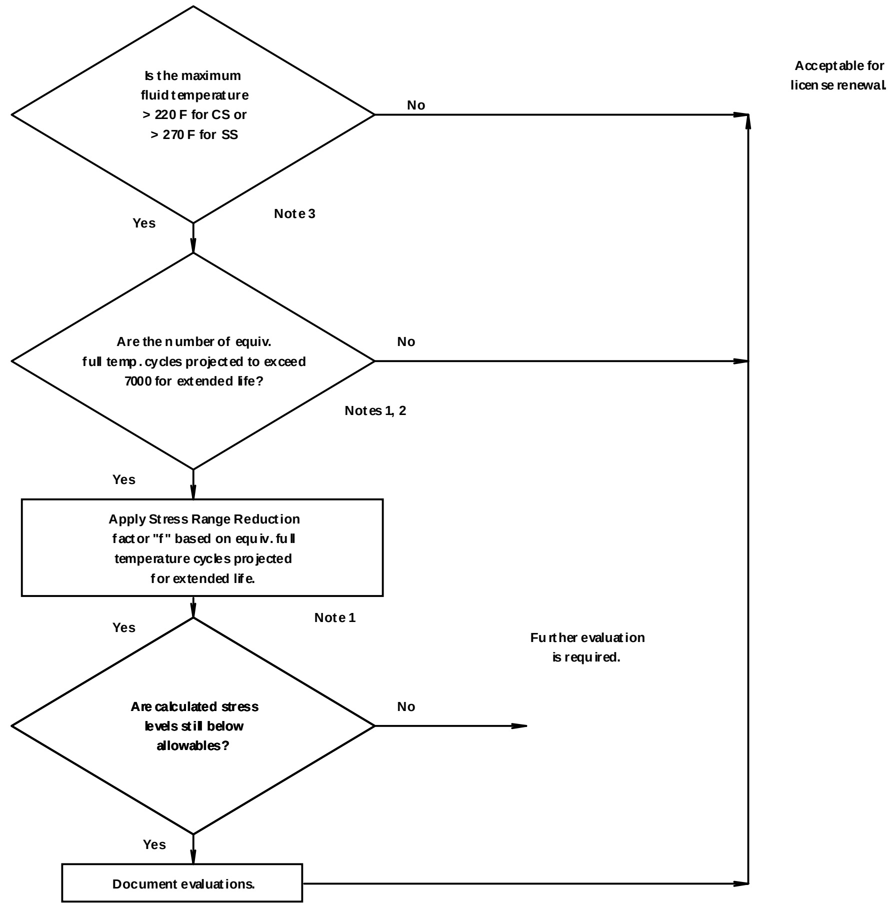
Design Codes for the following components do not require evaluation for fatigue. These components are acceptable for operation in the extended period associated with license renewal without further evaluation.

- ASME Section VIII Division 1 Components
- ASME Section III Class 2 and 3 (or Class B and C) Pumps
- ASME Section III Class 2 and 3 (or Class B and C) Storage Tanks (pressure < 15 psig)
- ASME Section III Class 3 (or Class C) Pressure Vessels
- AWWA or MSS Pumps and Storage Tanks

The following components may require evaluation for fatigue. See Figure 2 for additional details.

- ASME Section VIII Division 2 Components
- ASME Section III Class 2 Pressure Vessels and Heat Exchangers and Expansion Bellows

Figure 4-1 ANSI B31.1 and ASME III Non-RCPB Piping, Expansion Bellows, In Line Components, and CLB Requirements



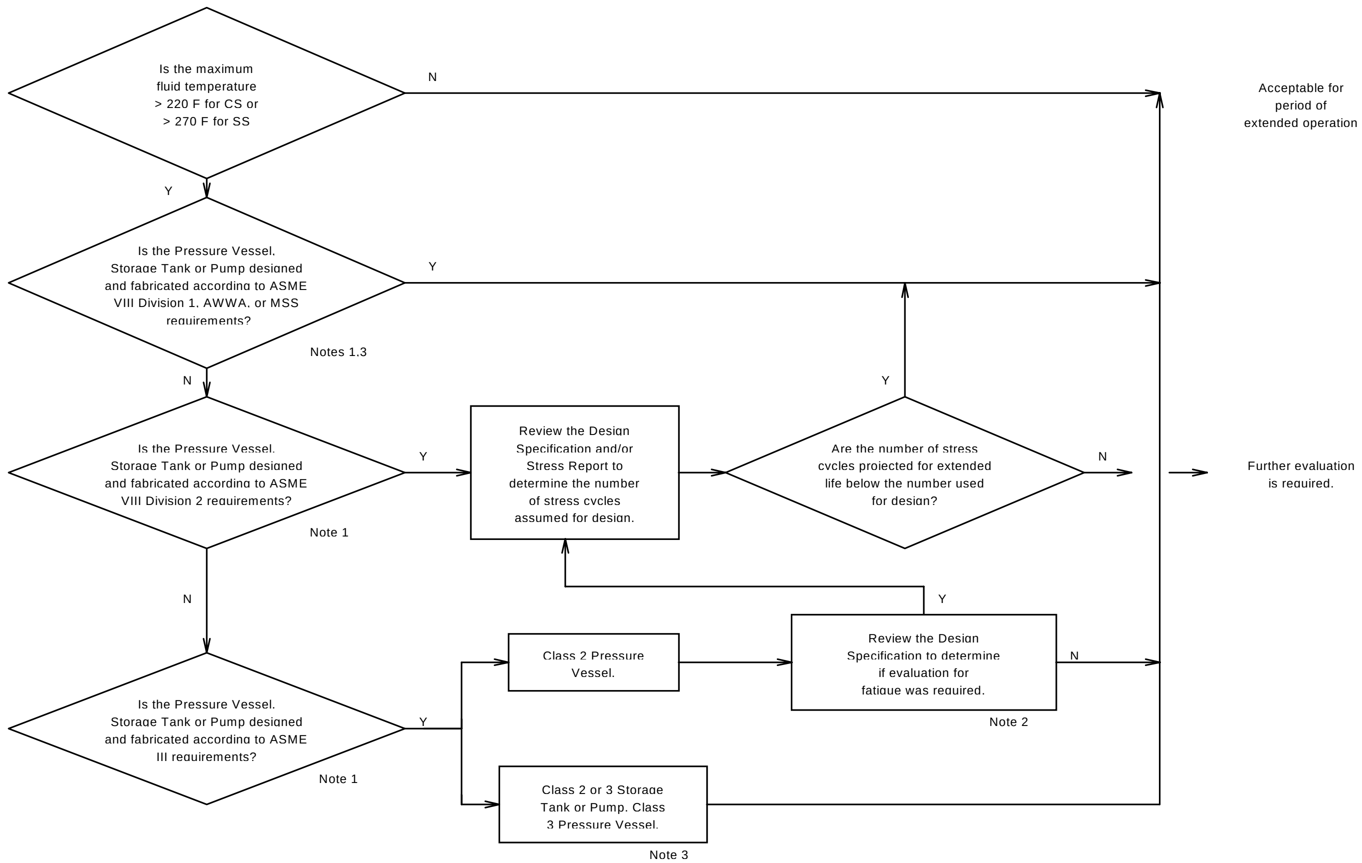
Notes:

1. If the range of temperature change varies, equivalent full temperature cycles may be computed in accordance with ANSI B31.1, section 102.3.2 or ASME III NC 3611.2.

2. Individual pipe stress calculations may be reviewed to determine if > 7000 cycles was assumed for the 40 year design basis calculations. If so, substitute that value in the cycle comparison.

3. Temperature limits from EPRI TR-104534, Vol. 2, Section 4.2

Figure 4-2 ASME III and ASME VIII Non-RCPB Pressure Vessels, Heat Exchangers, Storage Tanks and Pumps



Notes:

1. Code Data Reports, component nameplates, Design Specifications, Stress Reports, and contract files will indicate whether the Pressure Vessel, Storage Tank or Pump is designed and fabricated according to ASME VIII Division 1 or Division 2, ASME III Class 2 or 3, AWWA, or MSS requirements.

2. Under ASME III rules, only Class 2 Pressure Vessels designed according to subsection NC-3200 require evaluation for fatigue.

3. Fatigue evaluation is not required for ASME VIII Division 1 components, ASME III Class 2 and 3 Pumps, Class 2 and 3 Storage Tanks (pressure < 15 psig), Class 3 Pressure Vessels, and AWWA or MSS tanks or pumps.

5. CERTIFICATION

This appendix is an accurate description of aging effects of cracking due to thermal fatigue prepared for the B&W Owners Group Generic License Renewal Program.

Wayne A. Pavinich 8/14/99

Wayne A. Pavinich Date
Advisory Engineer

This appendix was reviewed and found to be an accurate description of the work reported.

Mark A. Rinckel 8/14/99

Mark A. Rinckel Date
GLRP Project Engineer

This appendix is approved for incorporation in the Implementation Guideline.

D J Firth 8/14/99

David J. Firth Date
GLRP Project Manager

6. REFERENCES

1. EPRI Fatigue Management Handbook, TR-104534-V1, -V2, and -V3, Research Project 3321-01, December 1994

Target:
Nuclear Power

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