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Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4

Technical Report

Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4

1010639

Final Report, January 2006

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This report supersedes EPRI report 1003056, *Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3,* which replaced EPRI TR-114882, *Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools.* TR-114882 was a republication of Revision 2 of the B&W Owners Group version of the report. The current report has been designated as Revision 4 to indicate the fourth revision of the original B&W Owners Group report.

REPORT SUMMARY

As part of the application process for license renewal, U.S. nuclear utilities must perform an evaluation to confirm that they have appropriately considered aging effects on plant components within the scope of the License Renewal Rule. An aging management plan must be developed for all Class 1 and non-Class 1 components subject to aging effects. This report presents a set of “mechanical tools” utilities can use to determine which aging effects are applicable to non-Class 1 mechanical components.

Background

Non-Class 1 mechanical components are those that are not within the ASME Section XI, Subsection IWB, Class I Inservice Inspection (ISI) boundary. Documentation of the non-Class 1 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 initially conducted research 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. EPRI published Revision 2 of the B&W report (TR-114882) as a set of Mechanical Tools for use by utilities in preparing license renewal submittals. This fourth revision of the Mechanical Tools incorporates changes that bring the document in line with current industry practices and recent operating experience, and includes comparison of the results to information contained in Volume 2 of NUREG-1801, Revision 1, “Generic Aging Lessons Learned (GALL) Report – Tabulation of Results.”

Objectives

- To document a generic evaluation to determine which aging effects are applicable to passive and long-lived non-Class 1 mechanical components, based on the material and environment(s) to which they are exposed, during normal plant operations
- To update the Mechanical Tools with recent industry experience related to the preparation and submittal of license renewal applications, including comparison to information in the GALL report

Approach

Due to the similarity of material and environmental conditions for mechanical components subject to AMR, the Mechanical Tools present a set of rules for determining whether certain material/environment combinations could result in age-related degradation in non-Class 1 mechanical components. The generic components addressed in these tools include: (1) heat exchangers, (2) tanks/vessels, (3) pumps, (4) valves, (5) piping, tubing, fittings, and branch connections, and (6) miscellaneous process components. Specialized tools are included for

evaluating bolted closures, heat exchangers, and fatigue. Aging effects evaluated include cracking, loss of material, change in material properties (such as reduction in fracture toughness and distortion), and loss of mechanical closure integrity. Environmental conditions considered include treated water, raw water, air or gas, lubricating oil and fuel oil, and external ambient environments. The project team evaluated each element of the Mechanical Tools and updated or revised them as necessary.

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. A cross-reference to pertinent NUREG-1801 (September 2005) Generic Aging Lessons Learned (GALL) Report item numbers and considerations is also provided. This approach resulted in a conservative set of rules for assessing applicable aging effects.

EPRI Perspective

The use of the Mechanical Tools presented in this report can greatly simplify the process for determining the aging effects applicable to a broad class of mechanical components for the license renewal period. Thus, the Mechanical Tools have the potential for dramatically reducing a portion of the effort required in developing and submitting a license renewal application. Related EPRI publications include *Aging Effects for Structures and Structural Components (Structural Tools) Revision 1* (EPRI report 1002950) and the *License Renewal Electrical Handbook* (EPRI report 1003057).

Keywords

Non-Class 1 mechanical components
Aging (materials)
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Aging management review
LWR

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Subsequent revisions of the report were prepared under the direction of the License Renewal Mechanical Working Group (LRMWG). The following members of the Working Group are gratefully acknowledged for their help, which led to the successful completion of the latest revision of this technical report.

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Although titled *Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4* (EPRI report 1010639), this document is a technical report that includes guidance and tools for the determination of applicable aging effects, based on material and the environment it is exposed to during normal plant operations. The guidelines and tools are intended for use in the performance of an aging management review (AMR) and should not be confused with information associated with the “Industry Materials Initiative” and/or the “Materials Guidelines Implementation Protocol.”

ACRONYMS

AFW	Auxiliary Feedwater
AIF	Atomic Industrial Forum
AMR	Aging Management Review
AMG	Aging Management Guideline (Sandia National Laboratory Document)
ASME	American Society of Mechanical Engineers
AWWA	American Water Works Association
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owners Group
BL	IE Bulletin (from the NRC)
BWNT	B&W Nuclear Technologies
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CASS	Cast Austenitic Stainless Steel
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CR	Circulars (from the NRC)
CRDM	Control Rod Drive Mechanism
CSCC	Caustic Stress Corrosion Cracking
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESC	Environmental Stress Cracking
FAC	Flow-Accelerated Corrosion
FCAW	Flux-Core Arc Welding
FEMA	Federal Emergency Management Agency
FIV	Flow-Induced Vibration
FSAR	Final Safety Analysis Report
GALL	Generic Aging Lessons Learned
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
HWC	Hydrogen Water Chemistry
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
MFW	Main Feedwater
MPC	Material Properties Council
MS	Main Steam
MSS	Manufacturer's Standardization Society
NEI	Nuclear Energy Institute
NPRDS	Nuclear Plant Reliability Data System
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
PAW	Plasma-Arc Welding
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RB	Reactor Building
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
SAW	Submerged Arc Welding Process
SCC	Stress Corrosion Cracking
SCs	Structures and Components

SER	Safety Evaluation Report
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

DEFINITIONS

The definitions for many of the terms used throughout this document are contained in either 10 CFR Part 54 or EPRI BR-101747 (*Common Aging Terminology: A Glossary Useful for Understanding and Managing the Aging of Nuclear Power Plant Systems, Structures, and Components*) and are not repeated here.

Component intended functions are component level functions that support system level intended functions.

Intended functions 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, non-safety-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 plausible for a given combination of material, environment, and stressors.

Class 1 mechanical components include those mechanical components that are 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 10 CFR 50.2.

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 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 of the applicant's plants (e.g., instrument lines, and tubing downstream of isolation valves or flow-restricting orifices).

REVISION SUMMARY

Revision History

Revision Number	Description
0	Initial Issue of BAW-2270
1	BAW-2270, Rev. 1
2	BAW-2270, Rev. 2 (republished as EPRI TR-114882)
3	Issued as EPRI report 1003056
4	Issued as EPRI report 1010639, with miscellaneous editorial/grammatical/formatting changes (for example, changes to section headings, tables of contents, and lists of tables, figures, and references) and the substantive changes itemized below.

Substantive Changes Made for Revision 4

Front Matter and Main Body of the Report (Implementation Guideline)

Section	Description
Front Matter	Updated acknowledgments for the License Renewal Mechanical Working Group review subcommittee; inserted remarks to distinguish between this technical report and the information associated with other industry activities related to materials and implementation; added a revision summary
Sect. 2.2.1	Updated listing of heat exchanger components in accordance with corresponding revision to Appendix G
Sect. 2.3	Updated general discussion of materials covered to include titanium (and titanium alloys), aluminum (and aluminum alloys), and non-metals
Sect. 3.2	Clarified discussion of Tool utilization (implementation) consistent with current industry considerations and experience, such as that mitigation programs (e.g., Chemistry) should also be included in license renewal evaluations
Sect. 4.1	Clarified discussion of demonstration of aging management consistent with current industry considerations and experience
Sect. 5	Added discussion and considerations for comparison to GALL, NUREG-1801 Rev. 1 (Sept. 2005), similar to material added to the Structural Tools, Rev. 1 (to target similarities with respect to applicable aging effects)

Appendices A-E

Section	**Description**
App. A Sect. 3.7.2 App. B Sect. 3.8.2 App. C Sect. 3.6.2 App. D Sect. 3.7.2 App. E Sect. 3.8	Updated NRC generic operating experience discussions, as applicable, based on review of generic communications (from the Tools Rev. 3 publication date through October 2005)
Sect. 4.4	Added discussion for comparison to pertinent GALL, NUREG-1801 Rev. 1 (Sept. 2005), items and definitions for material, environment, and aging effect(s) combinations
Sect. 4, 4.1, 4.2, 4.3, Tables and Figures	Updated summary of potential aging effects (last section of aging effects), assumptions, overview, tool description, figures, and tables (including reformatting, specifying pertinent GALL items, and providing discussion), consistent with other changes

Appendix A – Treated Water

Section	**Description**
Sect. 1	Clarified introduction, including a reference to Appendix B for treated water in drains/sumps that is considered as raw (untreated) water, a reference to possible use of the tool for submerged components, and an indication that fluoride thresholds may also apply to BWRs that rely on municipal water supplies
Various	Removed the identification of specific EPRI water chemistry guidelines/revisions from the text of the appendix
Sect. 2.1.6, 2.1.7, 2.1.8	Updated discussions of titanium and aluminum to include alloys of those materials, and discussion of non-metals to include more detail with respect to glass, plastics, and elastomers
Sect. 2.2, 2.2.1, 2.2.2	Updated discussion of environments to include sodium hydroxide and sodium pentaborate (used in BWR Standby Liquid Control systems vs. PWR borated water), and to more clearly differentiate between PWR and BWR water chemistry considerations
Sect. 3	Updated aging effect/mechanism evaluations relative to titanium and aluminum and their alloys, as applicable
Sect. 3.1.4, 3.1.5	Clarified evaluation of crevice and pitting corrosion, particularly of copper alloys
Sect. 3.1.1, 3.2.2	Updated evaluation of general corrosion and SCC of copper alloys (with regard to the presence of ammonia and oxygen)
Sect. 3.1.6	Updated evaluation of erosion and evaluation of flow-accelerated corrosion (per NASC-202L-R2)
Sect. 3.1.9, 3.2.3, 3.3.4	Added evaluation of caustic corrosion, evaluation of caustic cracking, and reference for caustic embrittlement

Sect. 3.2.2, 4.1	Clarified discussion of SCC, including considerations and thresholds; updated evaluation of SCC for nickel-base alloys and for carbon steel (per EPRI closed cooling water chemistry guideline)
Sect. 3.5	Added evaluation of fouling as an aging effect versus as a mechanism for loss of material
Sect. 3.6 (3.6.1, 3.6.2, 3.6.3)	Added evaluation of aging effects for non-metals

Appendix B – Raw Water

Section	**Description**
Sect. 1	Clarified introduction, including possible use of the tool for submerged components or those located in a splash zone
Sect. 2.1	Updated discussions of materials to include titanium and aluminum (and their alloys), non-metals, and protective coatings (consistent with current industry considerations and experience)
Sect. 2.2	Clarified environment discussion (and cover page) to indicate that previously treated water in drains/sumps is untreated and considered as raw water
Sect. 3	Updated aging effect/mechanism evaluations relative to titanium and aluminum and their alloys, as applicable
Sect. 3.1.4, 3.1.5, 3.1.1, 3.2.2	Updated/clarified evaluation of crevice and pitting corrosion, general corrosion, and SCC of copper alloys
Sect. 3.1.6	Clarified evaluation of erosion
Sect. 3.1.8, 3.5	Added evaluation of fouling (macrofouling) as a mechanism for loss of material and updated evaluation of fouling as an aging effect
Sect. 3.1.10	Added evaluation of exfoliation corrosion of aluminum/aluminum alloys with conclusion that it is not an applicable aging effect
Sect. 3.2.2	Clarified evaluation of SCC, particularly for nickel-base alloys
Sect. 3.2.1, 3.3.1	Moved evaluation of hydrogen embrittlement of titanium from cracking to reduction of fracture toughness and updated
Sect. 3.6 (3.6.1, 3.6.2, 3.6.3)	Added evaluation of aging effects for non-metals

Appendix C – Lubricating Oil and Fuel Oil

Section	**Description**
Sect. 1	Clarified cover page and introduction, including possible use of the tool to supplement Appendix G (for shells that contain lubricating oil), and to address aluminum/aluminum alloy and non-metal materials
Sect. 2.1	Updated materials discussions for aluminum alloys, non-metals (including determination of no applicable aging effects or reference to Structural Tools for elastomers), and coatings
Sect. 2.2	Clarified environment discussions and swapped the order (lubricating oil to 2.2.1 and fuel oil to 2.2.2) for consistency
Sect. 3	Updated aging effect/mechanism evaluations relative to aluminum/aluminum alloys and as applicable for other metals
Sect. 3.1.2	Clarified/simplified evaluation of galvanic corrosion
Sect. 3.1.3, 3.1.4	Updated/clarified evaluation of crevice and pitting corrosion, particularly of copper alloys
Sect. 3.1.5, 3.1.6, 3.1.8, 3.2.2	Clarified evaluation of erosion, MIC, selective leaching, and SCC (conclusion statements)
Sect. 3.2.1	Updated evaluation of hydrogen damage
Sect. 3.5	Deleted section for loss of closure integrity for consistency with other appendices; closure integrity is addressed in Appendix F

Appendix D – Air/Gas

Section	**Description**
Sect. 1	Clarified introduction with respect to materials and aging effects addressed by the Air/Gas tool, and to include a cross-reference to other appendices for related items (consistent with other appendices)
Sect. 2.1	Updated materials discussions for aluminum alloys and non-metals
Sect. 2.2.7	Added discussion of Halon as a gas environment
Sect. 3	Updated aging effect/mechanism evaluations relative to aluminum/aluminum alloys and change in material properties; removed identification of loss of closure integrity Updated evaluation of applicable degradation mechanisms to include the impacts of plant-specific operating experience that shows aggressive environments (e.g., coastal areas) in HVAC/air systems whose source is outdoor air
Sect. 3.1.1	Updated/clarified evaluation of general corrosion
Sect. 3.1.2	Clarified/simplified evaluation of galvanic corrosion (electrolyte in wetted or aggressive environment [e.g., coastal air])

Sect. 3.1.3, 3.1.4	Clarified evaluation of crevice and pitting corrosion, particularly of copper alloys
Sect. 3.2.2	Clarified evaluation of SCC for nickel-base alloys and copper alloys (plant-specific operating experience shows ammonia in the air)
Sect. 3.3.1	Updated evaluation of thermal aging of galvanized steel
Sect. 3.5	Replaced section on loss of closure integrity with evaluation of aging effects for non-metals, including a reference to the Structural Tools for elastomers and determination of no applicable aging effects for glass or plastics

Appendix E – External Surfaces

Section	**Description**
Sect. 1	Clarified cover page and introduction with respect to materials (including nickel-base alloys, titanium and titanium alloys, aluminum and aluminum alloys), insulation, and aging effects addressed by the tool
Sect. 2.1	Updated discussion of materials to remove reliance on Appendix A for detail on the materials addressed by the tool (added specific subsections for each material), including the addition of insulation
Sect. 2.2	Clarified discussion of environments addressed by the tool
Sect. 3	Clarified aging effects addressed, including a reference to Appendix A or B for submerged (splash zone) or continuously wetted components, and evaluation of aging effects in the embedded environment (reference to Structural Tools) Updated aging effect/mechanism evaluations as appropriate relative to nickel-base alloys, aluminum/aluminum alloys and titanium/titanium alloys Updated evaluation of applicable degradation mechanisms to include the impacts of plant-specific operating experience that shows aggressive environments (e.g., coastal areas)
Sect. 3.1.1	Updated evaluation of general corrosion
Sect. 3.1.2, 3.1.6	Clarified/simplified evaluation of galvanic corrosion (electrolyte in wetted or aggressive environment [e.g., coastal air]) and MIC
Sect. 3.1.3, 3.1.4	Clarified evaluation of crevice and pitting corrosion
Sect. 3.1.7	Updated evaluation of wear and fretting (determination that aging mechanisms are not applicable aging mechanisms for external surfaces, except in limited situations)
Sect. 3.1.10	Added evaluation of boric acid wastage
Sect. 3.2.1	Updated evaluation of hydrogen damage
Sect. 3.2.2	Clarified evaluation of SCC for nickel-base alloys and for copper alloys (presence of ammonia)
Sect. 3.6	Added evaluation of aging effects for non-metals and insulation (with the determination of no applicable aging effects for glass, plastic, or insulation, and reference to the Structural Tools for elastomers aging effects)

Appendix F – Bolted Closures

Section	Description
Sect. 3.1	Updated evaluation of loss of preload, including addition of and basis for 700°F, below which relaxation is not expected
Sect. 3.2	Updated evaluation of bolting SCC for closer consistency with corresponding discussion in the Structural Tools
Sect. 3.3	Clarified evaluation of loss of material
Sect. 4	Updated summary discussion, as applicable, based on other revisions, and added discussion (Section 4.1) for comparison to pertinent GALL, NUREG-1801 Rev. 1 (Sept 2005) items and definitions
Table 4-1	Added table comparing applicable aging effects per the tool to GALL items that address bolting (or closure bolting)

Appendix G – Heat Exchangers

Section	Description
Sect. 1.1, 1.2	Clarified discussion of tool scope consistent with current industry considerations and revisions to other tools
Sect. 4	Clarified description of in-scope heat exchanger component
Sect. 5; Tables 6-2 through 6-7	Updated clarifications and exceptions, as well as notes to summary tables, consistent with current industry considerations (and the revisions of the other tools)
Sect. 7	Added discussion and table (Table 7-1) for comparison to pertinent GALL, NUREG-1801 Rev. 1 (Sept. 2005) items and definitions
Tables 7-2 through 7-7	Added tables comparing applicable aging effects per the tool to GALL items that address heat exchanger components

Appendix H – Non-Class I Fatigue Screening Criteria

Section	Description
Sect. 2.2, 2.3	Clarified material and environment discussions consistent with revisions to the other tools and current industry considerations
Sect. 3.1.1	Updated NRC generic operating experience discussions, as applicable to high cycle fatigue, based on review of generic communications (from the Tools Rev. 3 publication date through October 2005)
Sect. 4, Figures	Added indication that "any local component residual stress and/or geometry specific stress intensification factors can result in lower temperature thresholds and, therefore, must be evaluated on a plant specific case-by-case basis" consistent with current industry considerations
Sect. 5	Added discussion and table (Table 5-1) for comparison to pertinent GALL, NUREG-1801 Rev. 1 (Sept. 2005) items and definitions
Table 5-1	Added table comparing tool screening criteria to GALL items that address cumulative fatigue damage

CONTENTS

LIST OF TABLES

1

INTRODUCTION

As part of the application process for license renewal, nuclear utilities must perform an evaluation of aging effects on plant components. An aging management program must be identified for components that are found to be subject to detrimental aging effects. This report presents a set of Mechanical Tools for use in determining which aging effects are applicable to non-Class 1 mechanical components.

The report was initially developed for the B&W Owners group as BAW-2270. In 2000, EPRI acquired Revision 2 of that document from the Owners Group, republished it as EPRI report TR-114882, and made it available to all EPRI members. The current document is Revision 4 of the original report. This revision updates the document based on recent industry experience with license renewal issues, including the development and review of license renewal applications.

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 tools used to identify material/environment combinations resulting in applicable aging effects. These aging effects include loss of material, cracking, change in material properties (e.g., reduction in fracture toughness, distortion), loss of mechanical closure integrity, and fouling (heat exchangers only). For license renewal, applicants must ensure, typically through a review of existing programs, that the identified aging effects are managed so that system and component intended function(s) are maintained in the period of extended operation.

The process by which license renewal applicants will identify structures and components (SCs) subject to an aging management review is plant-specific and is discussed briefly in Section 2.0. A general list of the mechanical components that may be subject to an aging management review is also contained 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 described in Section 4.0; however, the programmatic evaluation is a plant-specific task. The alignment of the Mechanical Tools with the information in Volume 2 of NUREG-1801, Revision 1, “Generic Aging Lessons Learned (GALL) Report – Tabulation of Results,” from the perspective of material, environment, and applicable aging effects/mechanisms (aging effects requiring management) is described generally in Section 5.0.

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, respectively.

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 aging management review (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 structures and components (SCs) subject to an aging management review is discussed in Section 2.1. A list of mechanical components subject to an AMR is provided in Section 2.2. Typical materials of construction are discussed in Section 2.3.

Although the non-Class 1 tools were not intended to include environments and materials found in Class 1 systems and components, the use of the non-Class 1 tools for Class 1 components is acceptable in certain instances. These instances would include situations where the Class 1 materials and environments are the same as the non-Class 1 materials and environments defined in this document.

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 Integrated Plant Assessment (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 AMR. An AMR must be performed on the identified components 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 both the CLB and system intended functions. Component intended functions (such as pressure boundary) 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 a plant's list based on plant-specific findings.

2.2 List of Mechanical Components Subject to an 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. For all such components, the component intended function must be documented for use during the aging management reviews. Some typical intended functions for passive mechanical components are listed in Table 4.1-1 of NEI 95-10 [1]. These intended functions include pressure boundary integrity, flow restriction, and heat transfer. 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 which are not relied upon for a pressure retaining function per ASME Section III (NX-2121). The systems, structures, and components within the scope of license renewal are set forth by 10 CFR 54.4. In particular, 10 CFR 54.4(a)(1)(i) defines as safety-related those SSCs relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a shutdown condition, or the capability to prevent or mitigate the consequences of accidents. Applicants can exclude from license renewal scope packing, gaskets, seals, and O-rings where these components are clearly not relied upon for a SSC to perform its intended functions. The applicant is cautioned that there may be instances (such as seals that ensure the pressure envelope of the control room or structural sealants) where the component may be passive, long-lived, and necessary for the system to perform its intended function. These components are included within the license renewal scope and should be subject to an aging management review. The applicant should include provisions for the discussed consumables so that the conclusions regarding whether such components are outside the scope of license renewal or are replaced based on qualified life or specified time period are unambiguous.

2.2.1 Heat Exchangers

The major pressure-retaining subcomponents of heat exchangers include:

- Shell (also known as case—includes nozzles, covers, manways, and handholes)
- Tubes
- Coils (may be fined for external flow)
- Coil (tube) headers (includes nozzles)
- Tubesheets (also known as tubeplates)
- Bolting
- End flange
- Channel head (also known as waterbox, end bell, bonnet or head—includes nozzles, covers, and a divider (partition) plate(s))
- Integral attachments

The component intended functions include pressure boundary and heat transfer (typically associated with tubes/fins/coils). Additional component information can be found in the Sandia AMG [4].

2.2.2 Tanks/Vessels

Tanks are normally divided into atmospheric and subatmospheric 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 subcomponents of tanks and vessels include:

- 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 subcomponents 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 (including pressure relief valves as defined in ASME Section III) are subject to aging management review. The pressure boundary subcomponents 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 (as well as adjusting screws and spring washers in pressure relief valves) are not subject to aging management review, because they perform an active function and are functionally tested [2].

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 subcomponents 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
- Containment or reactor building 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 and copper alloys, and various types of stainless steels (such as austenitic stainless steels and cast austenitic stainless steels). Typical material types used to fabricate piping are summarized in Table 2-1. Materials used in component fabrication may also include titanium and titanium alloys, and aluminum and aluminum alloys. Additionally, many pressure-retaining parts (sight glasses, HVAC duct seals, etc.) are fabricated of non-metallics such as glass, PVC (plastic), and neoprene (elastomer). 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 *Metals and Alloys in the Unified Numbering System*, published by the Society of Automotive Engineers, to identify material types (for example, 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, Grade 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 Grade KC70, Class1 API 5L Grade B (stainless steel) A 312 Tp 304 A 376 Tp 304 ASTM 358, Class1, 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) A 403 WP304 A 182 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) A 105 (stainless steel) A 182 F 304	(carbon steel) A 105 A 181 Grade 1 (stainless steel) A 182 F316 A 182 F304	(carbon steel) A 181 Grade I or II A 105

3

MECHANICAL TOOLS—APPLICABLE AGING EFFECTS

The aging effects to consider for non-Class 1 mechanical components subject to an aging management review include loss of material, cracking (initiation and growth), change in material properties (e.g., reduction of fracture toughness, 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) [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. The material- and environment-based tools are derived from known age-related degradation mechanisms and operating experience such as NPRDS and NRC generic communications. 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 tools 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 tools 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, because external environments, in some instances, can cause degradation. The External Surface Tool is discussed in Section 3.1.5.

A tool was prepared to identify aging effects for bolted closures. Gaskets are discussed in Section 2.2. 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 because they are typically exposed to multiple environments—for example, the shell side exposed to raw water and the 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 requirements of the TLAAs of the components identified in the IPA and is discussed in Section 3.1.8.

In addition, it is acknowledged that fabrication flaws that were within acceptable limits of the design code, may exist in the base metal and/or weld metal of non-Class 1 mechanical components. Although flaw growth is an applicable aging effect, fabrication flaws are by definition plant specific and time-limited. The tools cannot be used to identify whether a given plant has fabrication flaws. This plant-specific activity may be performed as part of the evaluation of time-limited aging analyses for license renewal. Additionally, 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, because 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-phase fluid), demineralized water, domestic water, intermediate/closed 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.

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 and that 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 microorganisms, 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. 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, Emergency Power Cooling Water, Emergency Service Water Spray Pond, Emergency Service Water, RHR Service Water, Service Water, and Fire Protection.

3.1.3 Lubricating Oil and Fuel Oil (Appendix C)

Fuel oil is defined as diesel oil, no. 2 oil, or other liquid hydrocarbons used to fuel diesel engines [3]. Fuel oil may be treated with a biocide for the control of microorganisms. Lubricating oil is defined as low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication [3].

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

Typical systems that contain lubricating 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 Air/Gas (Appendix D)

The air and gas environments within the scope of license renewal include atmospheric air, ventilation (filtered and unfiltered), instrument air, and compressed gases (CO_2, H_2, Halon, refrigerants, 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 Surfaces (Appendix E)

The external surface 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 handholes), 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, flange set surfaces, and pressure retaining bolting. Aging management programs required to ensure 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 aging effects. 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 Utilization of Mechanical Tools

NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR)" [7] provides the NRC's expectations for the evaluation of plant systems, structures, and components for license renewal. NEI 95-10 [1] provides further industry guidance on the implementation of 10 CFR 54, the license renewal rule.

With respect to the determination of aging effects, Appendix A.1.2.1, "Branch Technical Position – Applicable Aging Effects," of NUREG-1800 [7] clarifies that both degradations that have occurred and those that potentially could cause degradation based on materials, environment, stresses, service conditions, and operating experience should be considered. The effects of aging on the intended function(s) of structures and components should also be considered. In addition, the branch technical position indicates that aging effects should be identified as applicable even if there is a prevention or mitigation program associated with a given effect (so that the adequacy of the corresponding program is also included in license renewal evaluations), and that specific identification of aging mechanisms is not required.

When evaluating structures and components within a system, the boundary of the system should be determined 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 flow diagrams, piping and instrumentation diagrams (P&IDs), system descriptions, and design basis documents.

The evaluator must determine the operating modes of the system. Operating mode data should include 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 stresses that contribute to the aging of the passive mechanical components within the system. A correct definition of the environments and stresses is an integral part in the use of these tools and in the evaluation of structures and components for license renewal. As such, plant-specific operating experience should be considered during the evaluation that would, for example, serve to identify locations susceptible to condensation, pooling and concentration of contaminants, moisture intrusion to a dry air system, etc. Consideration of the related operating experience can refine evaluator assumptions about an environment and focus the evaluation to known problem areas and conditions, whereas the conclusions would otherwise agree with the logic of the tool.

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 combinations of aging effects 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. Furthermore, a full set of applicable aging effects is best obtained by the identification of an aging effect regardless of whether a prevention or mitigation program, such as water chemistry or a protective coating, is in place for the corresponding aging effect. Any plant program or activity credited with the prevention or mitigation of an aging effect should be evaluated (outside the scope of these tools), as described in Section 4.0, to demonstrate effectiveness.

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 can be used to identify applicable aging effects that must be managed. Applicants 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 effective 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 4.2.1.2 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 an example of demonstration of aging management. In addition, SERs of license renewal submittals provide examples of a demonstration of aging management for non-class 1 mechanical components applicable to these Mechanical Tools. Also, the Generic Aging Lessons Learned (GALL) Report [6] can be used as a resource and is discussed further in Section 5.0.

It is expected that in most instances existing programs will be found to adequately manage the applicable aging effects [8 (Abstract)]. However, for instances where existing programs do not fully assure the management of these aging effects during the period of extended operation, additional actions may be required.

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 license renewal applicant's FSAR supplement. In addition, commitments for additional actions will be captured in the FSAR supplement.

5

GALL COMPARISON

The Generic Aging Lessons Learned (GALL) Report, NUREG-1801 [6 and 8], is a two-volume document that contains the NRC staff's generic evaluation of existing plant programs and provides the technical basis for determining whether existing programs are adequate without modification and where existing programs should be augmented for the period of extended operation. The GALL report is referenced as a technical basis for NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR)" [7], which provides guidance to the NRC staff for the review of license renewal applications. The GALL report is **one** (but not the only) acceptable way to manage the effects of aging for the period of extended operation. Use of the GALL report is not required, but is expected to facilitate the timely, uniform review of a license renewal application by the NRC staff, and (to some extent) the preparation of the license renewal application [6].

As described in Section 4.0, the demonstration that aging effects are managed is a plant-specific responsibility. The GALL report, particularly the information contained in Chapter XI, Aging Management Programs (AMPs), of Volume 2, may be used in this plant-specific demonstration that is outside the scope of these Mechanical Tools. However, as part of the basis for the NRC staff determinations related to aging management during the period of extended operation, Volume 2 of the GALL report includes the NRC staff's generic aging management reviews (AMR) that are based on experience gained from numerous NRC staff reviews of license renewal applications and other insights identified by the industry [8]. Similar to the Mechanical Tools, these generic aging management reviews describe aging effects (and associated mechanisms) that require management during the period of extended operation based on the material of construction and the environment to which it is exposed.

The majority of the chapters in Volume 2 of the GALL report contain summary descriptions and tabulations of generic aging management reviews for a large number of components in the various major plant systems in light water reactor nuclear power plants. The major plant systems (system groupings) include the containment structures (Chapter II); structures and component supports (Chapter III); reactor vessel, internals, and reactor coolant system (Chapter IV); engineered safety features (Chapter V); auxiliary systems (Chapter VII); and steam and power conversion system (Chapter VIII). Also, Chapter IX of the GALL report, Volume 2, contains definitions of standard terms used within the GALL report for the various components, materials, environments, and aging effects/mechanisms [8]. Volume 2 information is summarized in Volume 1 of the GALL report, including the relationships of these items to items addressed in NUREG-1800.

With certain exceptions, the tabulations of aging effects requiring management in Chapters IV, V, VII, and VIII of the GALL report, Volume 2, are compared for similarity to the applicable aging effects described in these Mechanical Tools. The portions of the GALL Chapter IV tabulations that are specific to Class 1 mechanical components or considerations are not evaluated. The summary table of aging effect/mechanism criteria presented at the end of each appendix of this technical report is cross-referenced to the respective GALL report, NUREG-1801 Volume 2, item numbers. Information contained in the summary table is described in Table 5-1.

Table 5-1
Organization of the GALL Comparison Aging Effects Summary Tables

Column Heading	Description
Material	Lists the material(s) of construction for an item. (References Section 2.1 and the GALL Comparison discussion for each Appendix.)
Aging Effect/Mechanism	Lists the applicable aging effect/mechanism for an item. (References Section 3 and the GALL Comparison discussion for each Appendix.)
Mechanism Applicability Criteria	Provides criteria for a mechanism to be applicable to a material in the respective environment (e.g., to require management).
NUREG-1801 (GALL) Item No.	Lists the chapter-specific GALL item numbers (e.g., VIII.B1-1) that correspond to that material/environment and aging effect combination. Corresponding GALL item numbers are listed sequentially by chapter, system, and system-specific item number. The items for a given chapter are separated from items for other chapters. "None" denotes that there were no GALL items identified for the particular material/environment/aging effect combination.
Tools vs. GALL Match	The Mechanical Tools examine aging effects and mechanism applicability; the GALL provides aging management program recommendations for a given aging effect. "Yes" denotes that both the Mechanical Tools and the GALL recognize the aging effect/mechanism(s) as being applicable for that material/environment combination (requiring management in GALL). "No" denotes the evaluated conclusion of the aging effect/mechanism in the Mechanical Tools differs from the GALL's recommendation, or that the GALL does not list the aging effect/mechanism evaluated in the tool.
Relevant Sections, Assumptions, and Discussion	References the applicable section, and any assumptions associated with a material and applicable aging effect/mechanism for a given environment, and describes variations with the GALL report.

The tabulated generic aging management review results in Volume 2 of the GALL report also address the chapter-specific numbering of items, but these numbers lack any specified flow or order and it is the unique identifiers (e.g., VIII.B1-1) that lend to a system-by-system evaluation. The GALL report also includes a link or links to item numbers in the previous revision of the GALL that are not relevant to information in these Mechanical Tools.

Additionally, the tabulated GALL items are applied to particular components, whereas particular components are not addressed in these Mechanical Tools. Any component information that is pertinent to the comparison is described in the GALL comparison text or in the "Relevant Sections, Assumptions, and Discussion" section of the table. Another difference between the GALL and these Mechanical Tools is that a GALL item may list multiple mechanisms for an aging effect, while the Mechanical Tool items are mechanism specific. Also, the GALL report does not include the detailed mechanism applicability criteria provided in this technical report but does, in some cases, describe certain (but not all) of these criteria in the definition of the environment.

6
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7. NUREG-1800, Rev. 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR)," U.S. Nuclear Regulatory Commission, published September 2005.
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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, although nickel-base alloys, titanium, and titanium alloys may also be used. The remaining treated water systems may contain stainless steel, carbon and low-alloy steel, cast iron, copper and copper alloys (brass, bronze, copper-nickel), aluminum and aluminum alloys, nickel-base alloys, titanium and titanium alloys, and non-metals such as glass, plastics, and elastomers.

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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 water, steam, and two-phase flow. 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. Applicable aging effects include cracking, loss of material, change in material properties (e.g., reduction of fracture toughness, distortion), fouling, 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. Aging effects of materials exposed to external environments, such as humid air, that are not continuously wetted or in a splash zone are addressed in Appendix E. Aging effects for materials exposed to water that has not been demineralized (e.g., water from open/natural sources) or to treated water that has become chemically contaminated (e.g., drainage, waste processing) are addressed in Appendix B. Evaluation of heat exchangers is performed with the tool contained in Appendix G. Evaluation of thermal fatigue cracking is addressed in Appendix H.

This tool primarily addresses the combination of material and internal environment (process media that is contained) but can also be used to evaluate the combination of material and external environment for components that are submerged in a tank or pool, such as the suppression pool (BWR) or spent fuel pool. 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. Section 4.0 presents the development of the evaluation flowchart(s) and aging effects summary tables.

It is important to note that fluorides are not mentioned within the EPRI BWR Water Chemistry Guidelines [30]. Further discussions with BWR Water Chemistry Manual Guidelines committee members revealed that fluoride is simply not prevalent at BWR plants. However, BWR plants that use municipal water as a source for treated water makeup may be an exception that would need to be evaluated on a plant-specific basis. Therefore, all fluoride thresholds provided are applicable to PWR plants, but may also apply in some cases to BWR plants that use municipal water for makeup of treated water systems.

Thresholds for oxygen, chlorides, fluorides, and sulfates are provided for information. Aging effects shown as not a concern based on water chemistry are considered applicable aging effects that require management so that aging management programs, such as the chemistry program, are not implicitly credited by users of this tool but are evaluated for demonstration of aging management as discussed in Section 4 of the implementation guideline.

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, change in material properties (e.g., reduction of fracture toughness), or distortion. The term "treated water" comprises liquid water, steam, and two-phased flow environments. The materials addressed in this tool are discussed in Section 2.1 and the nuclear plant treated water environments are further described 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-base alloys (including nickel-base alloy weld metal), (3) carbon and low-alloy steels (including weld metals), (4) cast irons, (5) copper and copper alloys (brass, bronze, copper-nickel), (6) titanium and titanium alloys, (7) aluminum and aluminum alloys, (8) non-metals, and (9) 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 (and CF-8A), 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 increases the susceptibility to 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 Steels

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, which is addressed in Appendix F. 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 "white iron," "gray 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 and 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 and copper-based alloys generally have high corrosion resistance, copper and brass are very susceptible to erosion corrosion, partially due to the relative softness of the material [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 and 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 lower than yellow brass. The lower zinc content of this material provides high resistance to stress corrosion cracking and selective leaching [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 generally not a concern for copper nickel alloys in an aqueous environment unless sulfides are present.

2.1.6 Titanium and Titanium Alloys

Titanium alloys were originally developed in the early 1950s for aerospace applications due to their high strength to density ratios. However, the excellent corrosion resistance properties of titanium, specifically in chloride containing fluids, have led to widespread use in industrial applications, including the nuclear industry. The corrosion resistance of titanium is a result of the formation of a continuous, stable, highly adherent protective oxide layer on the metal surface. The metal itself is very reactive with a high affinity for oxygen and reforms damage to this layer instantaneously. However, anhydrous conditions in the absence of a source of oxygen may result in titanium corrosion [37].

Titanium and its alloys are fully resistant to water, all natural waters, and steam to temperatures in excess of 315°C (600°F). Slight weight gain is usually experienced in these benign environments along with some surface discoloration at higher temperatures. Typical contaminants in water, such as sulfides, sulfates, and chlorides do not compromise the passivity of titanium from finite passive film thickening. Titanium alloys exhibit negligible corrosion rates in seawater to temperatures as high as 260°C (500°F); passivity is not compromised by the typical contaminants (e.g., iron and magnesium oxides, sulfides, sulfates, carbonates, and chlorides) encountered [37].

The most commonly used grades of titanium in industrial applications include unalloyed titanium (ASTM grades 1-4) and alloys comprised of varying amounts of palladium, molybdenum, nickel, aluminum, and valladium (ATSM grades 7, 12, 9, and 5). Varying the alloy compositions gives slight differences in corrosion protection from one alloy to another, often at a higher cost. Within nuclear plants, titanium and titanium alloys are utilized in heat exchanger tubing and piping exposed to seawater, among other applications.

2.1.7 Aluminum and Aluminum Alloys

Aluminum is a reactive metal, but develops a strongly bonded oxide film which gives it excellent corrosion resistance in many environments. Once damaged, this film reforms immediately. This film is quite stable in neutral and many acidic solutions but is attacked by alkalies. While pure aluminum has a relatively low strength, alloying aluminum with materials such as copper, silicon, or zinc can impart the metal with a broad range of mechanical properties [7]. Aluminum alloys exhibit negligible action in boric acid solutions [16]. Aluminum and aluminum alloys are not resistant to high pH environments (for example, NaOH in Reactor Building Spray).

Because of the large number of available aluminum and aluminum alloy metals 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. There are two major categories of aluminum and aluminum alloys, wrought (1xxx – 9xxx) and cast (1xx.x – 9xx.x). However, for the purposes of this tool, differentiation between wrought and cast product forms is not required. Aluminum in the "1xxx" and "1xx.x" series/group is controlled unalloyed (pure) compositions ≥99.00%. Other aluminum compositions are aluminum alloys grouped by the major alloying elements. Series "2xxx," "2xx.x," "3xx.x," "7xxx," and "7xx.x" aluminum alloys, which include copper, are the least resistant to corrosion and cracking [37].

2.1.8 Non-Metals

Glass

Glass is an amorphous, inorganic oxide, mostly silica, cooled to a rigid condition without crystallization. Transparency is utilized for equipment such as flowmeters. Hydrofluoric acid and caustic attack glass, and it shows a slight attack in hot water. Uniform, selective, or localized attack can occur. When hot water attacks glass, it is not dissolved in the usual sense; it hydrolytically decomposes. There are a wide variety of glass compositions with modifiers, fluxes, and stabilizers added to obtain various properties, including corrosion resistance. Properties are also affected by thermal history (e.g., heat treatment) [7]. Because most silicate glasses have a high resistance to corrosion in normal environments, glass per se is frequently considered to be an inert substance. Silica is almost insoluble in an aqueous environment except at temperatures in excess of 250°C (482°F). Acid attack of soda-lime and borosilicate glass compositions is minimal due to the formation of protective, highly siliceous surface layer, except for hydrofluoric and phosphoric acids at high temperatures [45].

The major categories of traditional glass include soda-lime glass and borosilicate glass. Soda-lime glasses are the oldest, lowest cost, and most widely used, because of their transparency. They have fair to moderate corrosion resistance and are useful at temperatures up to 860°F annealed and 480°F in the tempered condition. Glasses containing boric oxide have excellent chemical and temperature resistance. These borosilicate glasses (e.g., Pyrex) are the most versatile and are used in such products as sights, gages, and piping. Another category of glass is the aluminosilicates. Aluminosilicate glasses are roughly 3 times more costly than the borosilicate types, but are useful at higher temperatures, with a maximum service temperature of 1200°F. Corrosion resistance to weathering, water, and chemicals is excellent (for aluminosilicates), although acid resistance is comparatively fair [41]. Additionally, heat resistant glass (e.g., 96% silica and fused quartz) is available and acceptable for high temperature applications, up to 1650°F [16, 41].

No definitive instances of glass failure due to an aging effect have been recorded in industry operating experience searches. Additionally, treated water environments do not contain hydrofluoric or phosphoric acids and only in limited instances, such as NaOH in Reactor Building/Containment Spray, do they contain caustics.

Plastics

Non-metal materials such as plastics are also used where temperatures, pressures, and stresses are not limiting and in media (such as aqueous chloride solutions) which cause localized corrosion in metals and alloys. While plastics do not dissolve like metals, they do potentially degrade due to moisture absorption (swelling), loss in mechanical properties, softening, hardening, and discoloration. When compared to metals and alloys, plastics are weaker, more resistant to chloride ions, less resistant to oxidizing acids, less resistant to solvents, and have much lower temperature limitations. A "plastic" is a material that contains as an essential ingredient an organic substance of large molecular weight, can be shaped by flow, and is a solid in its finished state. (In common usage, the words "plastic," "polymer," and "polymeric material" are often used interchangeably.) Some plastics (or polymers) occur in nature, but most are produced synthetically. Plastics are readily divided into two classes: thermoplastics and thermosets. The thermoplastics soften with increasing temperature and return to their original hardness when cooled. The thermosets harden when heated and retain hardness when cooled. Cold flow, or creep at ambient temperatures, is a problem particularly with the thermoplastics [7]. Thermosets, such as epoxies, phenolics, and resins, are discussed further in Section 2.1.9 below.

Polyvinyl chloride (PVC) is a thermoplastic material composed of polymers of vinyl chloride. Manufactured from sodium chloride (NaCl) and natural gas, PVC is relatively unaffected by water, concentrated alkalis, and non-oxidizing acids, oils, and ozone. While PVC begins to lose mechanical rigidity above 140°F, it is typically unaffected by sunlight and humidity changes [33]. Polyvinylidene fluoride (PVDF) is a member of the fluorocarbon family of plastics and is a homopolymer of vinylidene fluoride. Extruded as pipe, it is rigid and resists abrasion, as well as being chemically resistant, especially to halogens. It is impervious to deionized water which can cause organic and inorganic particulates to leach from PVC. PVDF is highly corrosion resistant and can withstand years of in-ground exposure to moisture and chemicals [34].

Unlike metals, thermoplastics do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of thermoplastics within a treated water environment is a design driven criterion.

Elastomers

Elastomers are defined as rubber or polymer that has properties similar to those of rubber. They are used in nuclear plants in various capacities, such as joint sealants, moisture barriers, and flexible connections. The outstanding characteristic of rubber and elastomers is resilience or low modulus of elasticity. Flexibility accounts for most applications. However, chemical and abrasion resistance, and good insulating qualities, result in many corrosion applications. Generally speaking, the natural rubbers have better mechanical properties than the synthetic or artificial rubbers (e.g., neoprene), but the synthetics have better corrosion resistance [7]. For example, natural rubbers, butyl rubbers, nitrile rubbers (Buna N), and Buna S are degraded by ozone and sunlight, whereas synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation) [7, 35].

2.1.9 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 steel, low-alloy steel, and cast iron applications also can be coated or lined.

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 180°F to 190°F. For example, a Technical Bulletin for Plasite 7155 [6] contains results of a test in a boric acid solution consisting of 1"x 5" 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 3.7); 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 manufacturer's requirements.

Aging degradation of organic coatings may not be a concern; however, as noted previously, 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 3.7 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 causes 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. Additionally, protective coatings cannot be credited in the determination of potential aging effects during Aging Management Review. Therefore, this tool does not take credit for any programmatic systems (such as protective coatings) in its determination of applicable aging effects for a given environment. However, 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."

Organic Outer Coatings

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

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. In addition, caustic solutions of demineralized water and sodium hydroxide (NaOH) are utilized at some nuclear power plants for pH control. Treated water is divided into two categories: borated and non-borated.

PWR systems that contain borated water are typically constructed from stainless steel and 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 decahydrate as a source of boron, as opposed to the boric acid (sodium tetraborate) used in PWR borated water systems. The Standby Liquid Control System typically uses a 13 to 19.6 wt% solution of sodium pentaborate, typically a mixture of Borax and boric acid with water, which has a pH range of 6.8 – 8.5 and is relatively benign to the typical materials in the system and much less aggressive than boric acid when concentrated.

Some of the PWR systems that contain non-borated treated water include main feedwater, main steam, intermediate or closed cooling systems, makeup water, emergency (auxiliary) feedwater, and diesel jacket cooling water (typically with an ethylene glycol mix). 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, control rod drive hydraulic systems, and diesel jacket cooling water systems.

2.2.1 PWR Water Chemistry

The following tables present recommended water chemistry for PWRs [3, 13]. They are included as generic information only; however, these chemistry limits were consulted when preparing the tool logic provided in Chapter 4 of this appendix. 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 @ 77°F	[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 @ 77°F	≤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 @ 77°F	≤1.0
pH @ 77°F	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 Water Chemistry Guidelines [3].

Table 2-3 PWR Auxiliary Feedwater Water Chemistry

PARAMETER	CONCENTRATION
pH @ 77°F	[a]
Dissolved Oxygen, ppb OTSG ≤ 250°F	Maintain hydrazine at $>3\times(O_2)$ @ STP
Dissolved Oxygen, ppb OTSG ≥ 250°F	≤10
Hydrazine, ppb	$\geq3\times(O_2)$
Conductivity, μS/cm @ 77°F	≤1.0

[a] Dependent on site-specific amine program.

Table 2-4 PWR Intermediate Cooling Water Chemistry

PARAMETER	CONCENTRATION
*pH @ 77°F	≈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

* FANP 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 steam generators. The addition of amines to control the pH of feedwater minimizes the corrosion of carbon steel and, thereby, reduces the iron transport to the steam generators. 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 steam generator 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 typical 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.

2.2.2 BWR Water Chemistry

The following tables present recommended water chemistry for BWRs [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 appendix. Each plant should compare specific chemistry limits when implementing this tool to verify all assumptions included in the logic.

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-section.

Table 2-5 BWR Feedwater/Condensate

PARAMETER	NORMAL POWER OP >10% POWER	STARTUP/HOT STANDBY (≥200°F 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 (≥200°F 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); however, tool logic does not depend on it

[b] Established by each plant; < -230 mV (SHE) suggested

[c] Consistent with applicant 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

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, condensate, and feedwater systems). Since the 1960s, the susceptibility of BWR components to IGSCC and other types of corrosion has been known. Significant research and testing has provided an understanding of aging mechanisms, and has developed water chemistries and methods that mitigate IGSCC. The guidelines and technical bases are found in the BWR Water Chemistry Guidelines [30]. This document strengthens the recommendation for hydrogen water 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) 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, thirty-one of thirty-six North American BWRs have implemented HWC.

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 FAC and IGSCC. These evaluations of IGSCC and FAC 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 FAC effects are well known and should be adequately addressed in the Water Chemistry and Flow-Accelerated Corrosion programs for each plant. 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 primarily in stainless steels. Specifically, the evaluation logic will default conservatively for this aging effect.

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 potentially applicable, 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 five categories: 1) loss of material, 2) cracking, 3) reduction of fracture toughness, 4) distortion, and 5) fouling. Reduction of fracture toughness and distortion are examples of a change in material properties. Other changes in material properties are also discussed, primarily for non-metals.

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, flow-accelerated corrosion (FAC), microbiologically influenced corrosion, wear/fretting, and in certain instances caustic corrosion. The cause of each aging mechanism is discussed in Sections 3.1.1 through 3.1.8.3.

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. The metal can thin down and fail by either penetration or lack of cross sectional area to support the required load. General corrosion requires an aggressive environment and materials susceptible to that environment. Wrought austenitic stainless steel, CASS, titanium and titanium alloys, nickel-base alloys, and aluminum and aluminum alloys are not susceptible to general corrosion in the treated water environments discussed in Section 2.2. However, carbon and low-alloy steels as well as cast irons are susceptible to general corrosion in systems using treated water. In addition, copper and copper alloys are susceptible to general corrosion in certain instances.

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 [16]. Dissolved oxygen is a major factor contributing to the natural corrosion of steel and is part of the overall electrochemical reactions occurring at the interface between the aqueous phase and the metal surface. In the absence of dissolved oxygen, the corrosion of steel is greatly reduced [37]. In some treated water systems, oxygen may be added for corrosion control. In such cases, some information on the degree of aeration and also on the effect of the solution on any oxygen that may be present in the bulk fluid is also important. Many organic compounds, for example, may react with oxygen and thereby effectively remove it from solution as far as corrosion is concerned [7].

Although general corrosion is, in many cases, predictable and can be accounted for by a corrosion allowance, it is an applicable aging mechanism for susceptible 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 material loss experienced will not prevent these components from performing their intended functions through the license renewal period. As long as any allowance used is adequate for the period of extended operation required for license renewal, general corrosion should not be a concern.

Copper alloys are used when resistance to general corrosion is required. These copper metals are used in atmospheric, fresh and salt water in place of other more susceptible metals such as carbon steel or cast iron [31]. General corrosion of copper and copper alloys results from prolonged contact with environments in which the corrosion rate is very low. A patina forms on copper and copper alloys from prolonged exposure, which gives the surface a weathered appearance. Other substances that cause uniform thinning at a faster rate include oxidizing acids, sulfur-bearing compounds, NH_3, and cyanides. Copper corrodes at negligible rates in unpolluted air, water, and deaerated non-oxidizing acids [37]. Copper alloys are resistant to neutral and slightly alkaline solutions with the exception of those containing ammonia, which causes stress corrosion (discussed separately) and sometimes rapid general attack [7]. However, due to the protective film which forms on the surface of copper and copper alloys combined with the very low (negligible) corrosion rates in water, general corrosion is not considered an aging mechanism for copper and copper alloys in a treated water environment, unless plant-specific operating experience indicates the presence of ammonia or ammonium salts (such as for pH control or in cleaning solvents), in which case the general attack of copper and copper alloys may be rapid and result in a loss of function.

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 [37].

Gray cast iron can also display the effects of selective leaching (also referred to as graphitic corrosion) 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, 37]. A two-phase or duplex structure is more susceptible. This degradation effect has been noted specifically in acid solutions; however, it was also noted that massive effects occurred in crevices 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, such as immersion in a corrosive or conductive solution [7]. Galvanic corrosion can only progress if the dissimilar metals are in contact in the presence of an electrolyte. Control of galvanic corrosion in treated water systems is possible by following the EPRI Chemistry Guidelines [3, 30, 46] for treated water systems. As treated water (per the Chemistry Guidelines) is a poor electrolyte, the dissimilar metals in this environment would experience little or no galvanic corrosion. This is evidenced by the lack of operating experience of galvanic corrosion failures in treated water systems. However, programs are not credited in the determination of potential aging effects. Therefore, all materials addressed in this tool are conservatively assumed to be in the presence of an electrolyte if they are normally wetted.

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, nickel-base alloys, or titanium and titanium 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 dissimilar metals are exposed to a conductive or corrosive environment and thereby electrically connected. 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 (e.g., stainless steel, titanium, or nickel-base alloy) acts as the cathode. The active (anodic) metal suffers an accelerated corrosion rate, while the more noble (cathodic) metal experiences a reduced corrosion rate. Therefore, wrought austenitic stainless steel, CASS, nickel-base alloys, and titanium and titanium alloys are not susceptible to loss of material because of galvanic corrosion. Anodic metals like aluminum will preferentially corrode when coupled with most metals (such as copper, stainless and carbon steel) in an electrolytically conductive environment.

When cast iron and other anodic metals are used in treated water systems and 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 and 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 and titanium alloys 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; and 5) using a sacrificial anode like zinc—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 steels, CASS, nickel-base alloys, or titanium and titanium alloys and are subjected to treated water may be susceptible to galvanic corrosion. Copper metals are also susceptible when coupled to the more cathodic stainless steels and when in contact with nickel-base alloys, titanium and titanium alloys, 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]. 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.

In addition to stagnant conditions in the crevice, an oxygen content in the fluid above 100 ppb is required to initiate 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 or the presence of contaminants such as chlorides 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].

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. Also notoriously susceptible to attack by crevice corrosion (given a sufficiently narrow crevice in the presence of oxygen) are stainless steels, aluminum or aluminum alloys, and other metals and alloys that depend on oxide films or passive layers for resistance to corrosion [7].

Titanium alloys generally exhibit superior resistance to crevice corrosion as compared to stainless steel and nickel-base alloys, but may be subject to localized attack in tight crevices exposed to hot (> 70°C or 160°F) chloride, bromide, iodide, fluoride, or sulfate-containing solutions. Crevice attack of unalloyed titanium or titanium alloys will generally not occur below a temperature of 70°C (160°F) regardless of solution pH or chloride concentration or when solution pH exceeds 10 regardless of temperature [37].

Crevice corrosion of copper and copper alloys is a result of conditions 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]. For most copper metals, the location of the attack is generally outside the crevice, immediately adjacent the crevice region. Classic crevice corrosion resulting from oxygen depletion and attack is less common in copper alloys. Aluminum and chromium bearing copper alloys, which form more passive surface films, are susceptible to differential oxygen cell attack. Local cell action similar to crevice attack may also result in copper and copper alloys from rust, permeable scales, or uneven accumulation of corrosion products on the metallic surface [37].

3.1.5 Pitting Corrosion

Some reactive materials such as titanium and titanium alloys exhibit excellent resistance to 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. The mechanism of pitting is very similar to crevice corrosion. However, while a macroscopic geometrical crevice determines the site of crevice corrosion, a microscopic topographical feature (such as MnS particles in carbon steels) determines the site of pitting corrosion. Nuclear plant materials, with the exception of titanium and its alloys, 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, aluminum and aluminum alloys, and cast iron [1, 7, 8, 17, 21]. Stagnant or low flow conditions which enable impurities to adhere to the metal surface are also required for pitting corrosion to occur in these metals. Areas where sludge piles and/or crevices exist are particularly susceptible to pitting corrosion.

Another form of pitting corrosion can occur at a gas to fluid interface. This form of corrosion is commonly called water-line attack [1]. Typically, a differential aeration cell is developed at the liquid surface leading to the localized attack just below the water line. All materials susceptible to pitting are susceptible to this type of attack.

Pitting is an aging mechanism for copper and 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]. Of the copper alloys, the most pit resistant are the aluminum bronzes with less than 8% Al and the low-zinc (< 15%) brasses. Copper nickels and tin bronzes tend to have intermediate pitting resistance, but the high Al and Zn copper alloys and silicone bronzes are somewhat more prone to pitting [37].

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 Flow-Accelerated Corrosion*

Erosion

Material loss because of erosion (liquid impingement) is possible only if the fluid contains particulates in the fluid stream (or water droplets in two phase flow) 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. 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 or two phase flow is present, erosion is a plausible aging mechanism. The resistance of specific metals to liquid erosion does not depend on any one property. However, ultimate resilience (one-half the square of ultimate strength divided by the modulus of elasticity) and hardness appear to be the best measures of resistance to erosion [40].

Wrought austenitic stainless steel and CASS are somewhat susceptible to erosion. Because liquid erosion is basically a surface phenomenon, stainless steel is commonly used as an erosion-resistant metal (such as for overlays) [40]. Relative to their hardnesses, titanium alloys and Inconel nickel-base alloys exhibit above average erosion resistance, similar to stainless steel, and so are also

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* Flow-accelerated corrosion is also referred to as erosion-corrosion in the literature, plant failure data, and the NRC generic correspondence.

somewhat susceptible to erosion [40]. Carbon steel, low-alloy steel, cast iron, copper and copper alloys, and aluminum and aluminum alloys are all susceptible to erosion [1, 7].

Cavitation Erosion

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 lead 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.

Flow-Accelerated Corrosion

Flow-accelerated corrosion (FAC) is the increased loss of material caused by relative movement between a corrosive fluid and a material surface. The normally protective oxide film dissolves into a stream of flowing fluid. The material removal process is considered to be one of oxide dissolution, i.e., during the FAC process, there is no mechanical removal of the surface material. The extent of FAC 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, and titanium and titanium alloys used in treated water environments are resistant to FAC [4, 19, 36, 37]. Aluminum and aluminum alloys are susceptible to FAC although in noncorrosive environments, such as high purity water, the stronger aluminum alloys have greater resistance to FAC [37]. However, aluminum or aluminum alloys are not typically used in treated water systems in locations susceptible to FAC.

Reference 18 suggests that flow rates less than 6 ft/sec will not cause FAC of carbon and low-alloy steels. However, Reference 36 states that although FAC wear rates tend to increase with increasing bulk velocity, there is no practical threshold velocity below which FAC does not occur. Piping layouts such as elbows, small radius changes of direction, and branch connections of 90-degrees are most susceptible to FAC [5, 22, 36]. Temperature, pH, and oxygen influence FAC in carbon and low-alloy steels. High pH levels (>9.5) can eliminate FAC as a concern [7, 36]. FAC rates are greatest at temperatures of 100 to 200°C (212 to 392°F) and decrease rapidly above and below this temperature range [5, 22, 36]. FAC occurs in both single-phase flow conditions, when temperatures are above 200°F, and in two-phase flow conditions, regardless of temperature [47]. Because removal of the oxide layer will only occur when the wall of the piping or components are continuously wet, FAC does not occur in lines transporting dry or superheated steam with no moisture content [36, 47]. Systems of low-alloy steel piping with nominal chromium content equal to or greater than 1-1/4% can be safely excluded from further evaluation for FAC. Systems with no flow, or those that operate less than 2% of the plant operating time, and systems with high levels of dissolved oxygen (> 1000 ppb) can also be excluded [47]. However, a plant-specific review of such systems may be needed if actual operating conditions cannot be confirmed, if only portions of a FAC susceptible line have a chromium content above the specified threshold, or if lines that operate less than 2% of the time have experienced damage caused by FAC.

Therefore, carbon steels, low-alloy steels, and cast irons are susceptible to a loss of material due to FAC if chromium content is less than 1-1/4% and the flow conditions are single-phase greater than 200°F or two-phase. FAC of copper and copper alloys is most often found with water containing low levels of sulfur compounds and with heavily chlorinated water [37].

Some of the systems which typically transport single phase fluid in the described temperature range and are susceptible to FAC include Condensate and Feedwater, Auxiliary (Emergency) Feedwater, Heater Drains, Moisture Separators Drains, Steam Generator Blowdown, and other drains. Typical two-phase systems which are susceptible to FAC include High and Low Pressure Extraction Steam Lines, Flashing Lines to the Condenser, Gland Steam (Seal Steam) Systems, and Feedwater Heater Vents [36].

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 FAC. 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, FAC is equally a concern in PWR secondary systems.

Instances of FAC have been observed and are discussed further in Section 3.7. Most all U.S. plants have made predictions of FAC rates using CHECKWORKS or other FAC modeling codes, consistent with the guidelines of EPRI NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program" [47]. All plants have flow-accelerated corrosion programs in place. The applicants 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.

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 120°F, however, microbes can withstand a wide range of temperatures (15 to 210°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, for example nitrate induced stress corrosion cracking. 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 and chlorides are low (<150 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 outdoor 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 in treated water when operating experience has shown a treated water system to be 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 occurs 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 treated water 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 Caustic Corrosion

The common alkalies, such as caustic soda (NaOH), are not particularly corrosive and can be handled in most applications where (solution) contamination is not a problem [7]. Therefore, the sodium hydroxide solutions used at nuclear power plants for pH control are no different than other water treatments except as discussed here and in Section 3.2.3.

Sodium hydroxide is commonly handled at ambient temperatures in all concentrations with carbon steel equipment. At temperatures above ambient, corrosion rates of carbon steel become greater. Caustic becomes increasingly corrosive with increasing temperature and concentration. Low-carbon steel is effective in caustic solutions up to 50% concentration and at temperatures to 90°C (190°F). Cast iron also shows corrosion performance similar to steel and has proven quite useful in certain applications up to 70% concentration and 90°C (190°F) [37]. Austenitic stainless steels, primarily types 304 and 316, are very resistant to caustic in concentrations up to 50% and temperatures to about 95°C (200°F) [37]. The austenitic stainless steels are better than carbon steel, but for the tough jobs (high concentrations and high temperatures) nickel-base alloys are preferred. Nickel and nickel alloys are used extensively for combating corrosion by caustic. Nickel is suitable under practically all conditions of concentration and temperature. In fact, the corrosion resistance to caustic is almost directly proportional to the nickel content of the alloy [7]. Titanium and titanium alloys are very good in moderate concentrations and temperatures, but when attacked, absorb hydrogen liberated in the corrosion process, limiting service to temperatures of about 100°C (210°F) and to concentrations generally below 50%.

Certain metals should not be used with caustic because of excessive corrosion rates, including aluminum, magnesium, zinc, tin, chromium, and zinc-containing brasses or bronzes [37].

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, fatigue, and in certain instances caustic cracking (also known as caustic SCC). 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 300°F [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 processes [7].

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 and its alloys are immune to hydrogen damage, although nickel-base alloy may be somewhat susceptible [7, 10, 16, 20].

Titanium and titanium alloys have demonstrated a tendency toward hydrogen embrittlement although a mechanism for the generation of atomic hydrogen must be present. This could include the titanium in contact with a corroding metal (galvanic couple), an impressed cathodic current, corrosion of titanium, or severe continuous abrasion of the titanium surface in an aqueous medium. Additionally, the metal temperature must be greater than 175°F and the solution pH must be outside the 3 to 12 range. The dissolved hydrogen reacts to form a brittle hydride compound which results in the loss of ductility and tensile strength. Avoiding any of the above conditions will prevent hydrogen embrittlement of titanium [37]. Refer to Section 3.2.3 for a discussion of the susceptibility of titanium and titanium alloys to cracking due to hydrogen embrittlement in a caustic solution.

In summary, a review of the failure data for BWR and PWR treated water systems shows no evidence of historical hydrogen blistering. As stated above, both occur primarily in the petrochemical industry during the refining process. With the exception of fuel oil storage tanks and associated piping, it is not expected that equipment within the scope of this tool will experience the corrosive environment necessary for hydrogen damage. These tanks and associate piping are susceptible to hydrogen damage if cathodic protection is used with an incorrect voltage setting.

Therefore, hydrogen damage is considered not applicable to carbon steel, low-alloy steel, stainless steel, titanium and titanium alloys, cast iron, aluminum and aluminum alloys, and copper and copper-based alloys for treated water systems, except as described in Section 3.2.3.

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. These modes can be mixed or the mode can switch from one to the other. 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. IGSCC is the predominate form of SCC in BWRs. 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 [37].

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 are beyond the scope of this tool. Increasing the stress tends to decrease the time for cracking to occur. The criteria for the stresses are simply that they be tensile and of sufficient magnitude. Additionally, stresses up to 10,000 lb/in^2 can be generated by corrosion products in constricted locations. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and the environment [7]. As such, it is extremely difficult to identify a minimum threshold stress level for SCC. Therefore, it is assumed that materials evaluated using these tools contain stresses sufficient to initiate SCC if subjected to a corrosive environment. The user of this tool is cautioned that thresholds (e.g., temperature) for whether an environment is corrosive with respect to SCC for a given material may be impacted by specific component residual stresses and geometry-specific stress intensification factors. Therefore, the assumptions included in the logic should be verified for each plant.

A discussion of the susceptibility of austenitic stainless steels, nickel-base alloys, copper and copper-based alloys, carbon and low-alloy steels, titanium and titanium alloys, and aluminum and aluminum alloys to SCC or IGA in a treated water environment is provided below. The susceptibility of these materials to a cracking in a caustic solution is provided in Section 3.2.3.

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 150 ppb) at temperatures greater than 200°F and dissolved oxygen levels greater than 100 ppb [10]. The presence of impurities such as sulfates > 150 ppb, chlorides >150 ppb, or fluorides > 150 ppb (primarily a PWR consideration) are all by themselves sufficient to initiate SCC in austenitic stainless steels [9, 10]. In general, SCC very rarely occurs in austenitic stainless steels below 140°F [27, 37]. Although SCC has been observed in stagnant, oxygenated borated water systems at lower temperatures than this 140°F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. With a harsh enough environment (significant contamination), SCC can occur in austenitic stainless steel at ambient temperature. However, these conditions are considered event driven, resulting from a breakdown of chemistry controls.

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 3.7 and 4.0.

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 [3] uses a threshold level for sulfates of 150 ppb to require corrective action.

For a discussion of SCC in stainless steel components influenced by BWR hydrogen water chemistry (HWC), see Section 2.2.2.

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. SCC of nickel-base alloys has been found to occur in three types of environments: high-temperature halogen ion solutions, high-temperature waters, and high-temperature alkaline environments (addressed in Section 3.2.3) [37]. As a class, nickel-base alloys are susceptible to SCC by a wide variety of corrodents. However, in most cases, the corrodents are specific to a few, but not all, of the alloys in this class. For example, sensitized alloys (e.g., 800 and 600) crack in thiosulfate solutions, but stabilized alloys (e.g., 825 and 625) are resistant. Inconel 600 and weld metal alloys 82 and 182 crack intergranularly in crevices in high-purity water containing oxygen at elevated temperatures and pressures. In the absence of crevices, these alloys are resistant. Inconel 690 is resistant under all conditions [37]. Additionally, precipitation-hardenable nickel alloys (e.g., X-750) corrode intergranularly in high temperature water containing low concentrations of chlorides or other salts [37, 40].

Therefore, it is conservatively assumed that the threshold values of impurities reported above for austenitic stainless steels apply to nickel-base alloys (i.e., sulfates >150 ppb; chlorides > 150 ppb; and fluorides >150 ppb—primarily a PWR consideration), particularly if the impurity is a thiosulfate ($Na_2S_2O_3$), as does the threshold value for dissolved oxygen (>100 ppb). However, a more significant factor in the susceptibility of nickel-base alloys to SCC is temperature [37]. Recent studies of Alloy 600 in a PWR environment [11] show that SCC occurs when high tensile stress, high temperature, and a susceptible microstructure are simultaneously present. This form of intergranular SCC is known as primary water stress corrosion cracking (PWSCC). All failures of Alloy 600 components reported in the field resulted from high residual tensile stresses introduced primarily during fabrication. Other factors that may possibly influence susceptibility include high lithium and high hydrogen content.

PWSCC susceptibility of Alloy 600, as well as Alloy 82 and Alloy 182 weld metals, is low when the temperature is less than 600°F [11]. A PWSCC screening threshold temperature of 500°F was chosen to conservatively apply to this Mechanical Tool. Therefore, PWSCC in nickel-base alloys is considered to be significant only when exposed to temperatures greater than 500°F and to reactor coolant chemistry conditions described in the EPRI Water Chemistry Guide for the RCS [3]. The susceptibility to SCC of nickel-base alloys in non-primary water systems is also considered to be a concern when exposed to temperatures greater than 500°F in the presence of impurities and oxygen.

SCC of Copper and 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 and 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 produced 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 (brass) 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]. SCC is not possible in pure copper [38].

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. Generally, steels with lower strengths are susceptible to SCC only upon exposure to a small number of environments, such as hot caustic solutions (addressed in Section 3.2.3), hot nitrate solutions, and anhydrous ammonia [37]. Anhydrous ammonia is not an applicable environment in the nuclear plant treated water systems and 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. As described in Section 3.1.7, several forms of anaerobic organisms (nitrifying bacteria) can metabolize NO_3, which is used widely as a corrosion inhibitor in closed cooling water systems, and produce byproducts including nitrates. Nitrates are generally not harmful in closed cooling water systems but have been reported to contribute to SCC of carbon steel under certain conditions at high concentrations, in the range of 10,000 ppm (1%). An increase in nitrate concentration is primarily an indicator of nitrifying bacteria [48]. Therefore, for the purposes of this tool, SCC of carbon and low-alloy steels is considered an applicable aging mechanism only in treated water systems in which a nitrite corrosion inhibitor is used, and that have a potential for MIC contamination and the necessary conditions of pH and temperature described in Section 3.1.7 SCC in higher strength bolting materials is discussed in the Bolted Closure Tool in Appendix F.

SCC of Titanium and Titanium Alloys

Grades 1, 2, 7, 11, and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO_3), and liquid cadmium) [37]. None of these specific environments are applicable in treated water systems. Other titanium and titanium alloys have been found to be susceptible to additional environments, most notably aqueous chloride solutions. However, this susceptibility is seldom observed in actual field applications [37]. In general, titanium alloys with higher aluminum, oxygen, and tin content are the most susceptible to SCC, whereas molybdenum is usually beneficial in increasing SCC resistance. In binary titanium-aluminum alloys, it has been established that 5% Al is necessary for SCC to occur in aqueous environments. Binary titanium-oxygen alloys also exhibit a critical level of oxygen below which SCC does not occur. This level is generally taken as less than 0.20 to 0.25% [37].

For the purposes of this tool, SCC of titanium and its alloys is considered an applicable aging mechanism in treated water systems, in the presence of chlorides, if the titanium alloy is not ASTM grade 1, 2, 7, 11, or 12 and contains more than 5% aluminum or more than 0.20% oxygen, or any amount of tin.

SCC of Aluminum and Aluminum Alloys

Pure aluminum is not susceptible to SCC. However, aluminum alloys containing more than 12% zinc or more than 6% magnesium are very susceptible to cracking under mild corrosive environments [16]. Aluminum alloys that contain appreciable amounts of soluble elements (primarily copper, magnesium, and zinc) are susceptible to SCC in water and water vapor environments with halides (such as chloride). Alloys of the 2xxx, 5xxx, 6xxx, and 7xxx groups of wrought aluminum alloys are susceptible to SCC. Resistance of other wrought alloys and cast alloys, except for 3xx.x and 7xx.x, is sufficiently high that cracking rarely occurs in service [37].

3.2.3 Caustic Cracking

Caustic cracking (historically termed caustic embrittlement) is a form of stress corrosion cracking most frequently encountered in carbon steels or iron-chromium-nickel alloys that are exposed to concentrated hydroxide solutions at temperatures of 400°F to 480°F. However, the concentration of NaOH necessary for producing cracking increases as temperature decreases [40]. Cracking of steel and iron, due to caustic stress corrosion cracking (CSCC), has been reported at temperatures as low as 120°F with a concentration of 50%, but a practical (safe) limit is 150°F for a 50% NaOH concentration, allowing higher temperatures for dilute, nonconcentrating solutions. Steel construction is suitable in NaOH concentrations of 10% or less up to 190°F, where no potential exists for localized solution concentration or severely stressed conditions. The CSCC behavior of alloy steels, high-strength low-alloy construction steels, and abrasion-resistant steels does not differ significantly from that of carbon steel. Caustic stress corrosion cracking is not a problem for cast irons [37].

Based on known failures of austenitic stainless steel by CSCC, cracking may occur above 220°F. Fortunately, the conditions leading to caustic cracking of austenitic stainless steel are more restrictive than those leading to chloride cracking. Temperatures near or above the boiling point at ambient atmospheric pressure are required and very concentrated caustic solutions are typically necessary. Although austenitic stainless steels crack readily in neutral and acid chlorides above 140°F, the effect of chlorides in an alkaline solution seems to be nil. As long as the solution remains alkaline, the mode of stress cracking is CSCC. A solution of 0.5 g/L NaOH with a pH of 12 is sufficiently alkaline [37]. Susceptibility of austenitic stainless steels to CSCC usually becomes a problem when concentrations exceed approximately 25% and temperatures are above 212°F. Cracking occurs most often in the weld heat-affected-zone (HAZ) [37].

Titanium metals are very good in moderate caustic concentrations and temperatures (e.g., subboiling) [37]. Furthermore, the hydrogen uptake in titanium metals that may result from caustic corrosion, as described in Section 3.1.8.3, can cause embrittlement and cracking of titanium and titanium alloys that would be otherwise immune to SCC. As such, the thresholds for CSCC of stainless steels are conservatively considered to be applicable to titanium and titanium alloys and to effectively bound the conditions where caustic corrosion, and the resulting hydrogen uptake/cracking, would be a problem.

Nickel or nickel-base alloys are extensively used in more severe applications and are essentially immune to CSCC [37]. The lower-carbon nickel-base alloys should be used at temperatures above 600°F to avoid graphitic precipitation. However, concentrations of 10% NaOH have been found to cause CSCC of nickel-base Alloy 600 at temperatures of 550°F [37].

3.2.4 Fatigue

Fatigue cracking of carbon, low-alloy, wrought austenitic stainless steel, CASS, 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, as well as titanium and titanium alloys, is typically higher than the fracture toughness of carbon steels, low-alloy steels, and cast iron. Aging mechanisms that may lead to reduction of fracture toughness are thermal embrittlement, radiation embrittlement, hydrogen embrittlement, and in some instances caustic 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 metals, and nickel-base alloys are not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments [4, 25, 26, 27, 28]. Likewise, titanium and titanium alloys are not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments. Titanium has no debilitating ductile-brittle transition temperature, and the maximum useful temperature range is 800°F to 1100°F [41]. 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%) [Reference 12; Figure 1]. 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 [4] and EPRI report TR-106092 [12], which also contains more specific screening criteria based on casting method (static vs. centrifugal), molybdenum content, and ferrite content.

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 irons, wrought austenitic stainless steels, CASS, copper metals, nickel-base alloys, and titanium and titanium 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.

3.3.4 Caustic Embrittlement

See discussion in Section 3.2.3.

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 temperatures > 40% of the alloy melting point) are not observed in nuclear plant systems [10].

3.5 Fouling (Flow Restriction/Reduction of Heat Transfer)

Fouling is an accumulation of deposits. Water-borne deposits, commonly known as foulants, are loose, porous, insoluble materials suspended in water. They include such diverse substances as particulate matter, migrated corrosion products, etc. [37]. Deposits may be organic, inorganic, or a mixture of the two. Scales are crystalline deposits that precipitate in a system. Fouling can impede heat transfer or fluid flow in equipment and piping [37]. Some NRC or industry documents may refer to fouling as a mechanism for loss of material. As described in Sections 3.1.4, 3.1.5, and 3.1.7 respectively, this tool recognizes that corrosion products and other deposits can contribute to the occurrence of crevice corrosion, pitting corrosion, or microbiologically influenced corrosion (MIC).

Fouling causing a reduction of heat transfer applies only to heat exchangers and is addressed in Appendix G. Plugging (flow restriction) of spray and sprinkler nozzles may be an issue, but is not likely in treated water environments, which are typically high quality water and filtered.

Macrobiological fouling (macrofouling) is also not a concern in treated water environments, as aqueous macroorganisms (such as barnacles, mussels, clams, and algae) are found only in raw water systems. Operating experience has not shown flow restriction from corrosion product build-up to be a significant issue in treated water environments. However, the user of this document should review the latest industry developments with respect to the treatment of flow restriction as an aging effect.

3.6 Change in Material Properties/Cracking – Non-Metals

The effects of aging on glass, thermoplastics (e.g., PVC and PVDF), and elastomers are conservatively addressed in the subsections below, although detrimental aging is not expected in nuclear power plant treated water environments based on industry operating experience and the assumption of proper material selection and application. For additional information on the properties and failure susceptibilities of glass, plastic (thermoplastics and thermosets), and elastomers, the user of this tool is referred to Volume 4, "Ceramics and Glasses," and Volume 2, "Engineering Plastics" [34], of the Engineered Materials Handbook published by ASM International, copyright 1991 and 1988 respectively. Alternatively, the ASM Engineered Materials Handbook is available in a desk edition, copyright 2003 [39].

3.6.1 Glass

Glass is resistant to practically all corrosive agents except hydrofluoric acids and the caustic alkalies, under some circumstances [16]. Even with concentrations as low as 20 ppm, fluorides in an acid environment corrode glass severely. In the liquid phase, fluorides will severely etch glass and produce a roughened surface; while in the vapor phase, the attack is more localized and concentrated, evidenced by chipping and pinholes [37]. However, treated water environments do not contain hydrofluoric acids.

Alkaline attack is much more severe than acid attack. The greater the concentration and pH of the alkali, the greater the amount of corrosion, which is evidenced by pinholes and chipping. Glass and other ceramics have very limited applications in NaOH, especially if high temperatures and concentrations are involved. Borosilicate glass (Pyrex) is especially sensitive to caustic attack in hot solutions (200°F) as low as 5% concentration [37]. However, the rate of attack by alkali appears to fall off with time [16].

Steam at 100 psi measurably attacks glass, but at a low rate [16]. Water can cause corrosion of glass, and the severity increases with water purity and temperature, becoming greatest above the boiling point [37]. This chemical attack of glass surfaces occurs through either dealkalization or dissolution. Water, e.g., droplets or vapor, reacts with the glass surface and causes sodium-ion exchange (or leaching) from the glass. The high-pH surface film that results causes accelerated attack of the glass. Weathering of glass occurs either when alkali is leached from the glass under high humidity or when the glass surface is exposed to alternating cycles of moisture condensation and evaporation [39].

Silicate glasses, which comprise nearly all glasses of commercial interest, are linearly elastic, brittle materials. Brittle materials fail in tension. Brittle materials are known to be susceptible to subcritical crack growth in monotonic tension under the influence of an environment. The mechanism is stress corrosion, crack growth caused by stress-assisted reaction with liquid water or water vapor at the crack tip, and is referred to as static fatigue in the glass literature. For most inorganic glasses, moisture is responsible for enhanced subcritical crack growth and for deterioration in strength and other mechanical properties. The water decreases the stress required to propagate an initial crack and cause failure at a lower applied stress. The susceptibility of a given glass to static fatigue increases when more water is present and when the glass exhibits more surface damage. However, models of water attack are just that—models, and the specific attack mechanisms are still not known with certainty. With rare exceptions, surface cracks are the sources of failure (the fracture origins) in glasses because glasses usually have few internal flaws, maximum tensile stresses are typically on the surface, and any surface cracks are exposed to the environment [43].

Glass is typically not used in steam or other treated water environments above the boiling point and proper glass composition selection is assumed for any use of glass exposed to NaOH concentrations. Also, surface cracks and flaws are minimal in glasses typically used in treated water environments, and the age-related causes of surface damage that could result in subcritical crack growth (or slow crack growth) are limited to NaOH concentrations and/or high temperature water, as described above. As such, this tool does not include a logic for further evaluation of the effects of aging in a treated water environment on glass.

3.6.2 Plastics (Thermoplastics)

The chemical resistance of many engineering plastics is excellent. However, most have specific weaknesses in terms of chemical attack. Various engineering plastic families vary widely in the degree of chemical resistance they exhibit. Typically, plastics fail because of chemical exposure in several characteristic ways, which can be classified as plasticization, chemical reaction, and environmental stress cracking (ESC). Plasticization may occur from exposure to a fluid with which a plastic is somewhat miscible; the solvent penetrates the plastic, which swells, softens, and gains weight and physical dimension, while the strength and stiffness decrease. Chemical reaction between a plastic and an environmental substance may result in lowered molecular weight and degraded mechanical properties. A stressed plastic may develop crazing and cracking, when exposed to an aggressive substance, that results in rapid propagation and sudden brittle failure [39].

Another consideration for the degradation of polymers is the fact that their mechanical properties may severely deteriorate with exposure to heat and/or light, if the polymers employed are not properly stabilized. Mechanical stress is known to enhance degradation effects, and surface embrittlement and consequent microcracking may occur. With many polymeric materials, ultraviolet (UV) radiation can be the source of energy that will abstract an atom from the polymer and start the degradation process. Oxidation initiated by UV radiation will result in eventual loss of properties as well. A plastic may contain chemical additives that will retard these processes, but eventually they will be consumed and degradation will proceed [44].

Certain polymer types are more susceptible than others to specific degradation mechanisms, but all polymers can be degraded by at least one mechanism. Certain polymers form water as a reaction product along with the polymer, and in certain aqueous environments the reaction can be reversed and the polymer broken down. Normally these hydrolytic degradation reactions occur at extremely slow rates, however, at conditions of either low (< 4) or high (> 10) pH, the rate of hydrolysis may become perceptible. High molecular weight polymers will also break down upon exposure to elevated temperatures. Also, many polymers will oxidize when exposed to oxygen-containing environments. Virtually all plastics are stress cracked by some chemical environments. The biggest problem with this is that each plastic has its own set of stress cracking reagents, and those chemicals that stress crack one type of plastic will have no effect on others [44].

Therefore, the acceptability for use of thermoplastics within a treated water environment is a design driven criteria and once the appropriate material has been selected, there should be no applicable aging effects. For example, vinyl polymers and copolymers (e.g., PVC) show no effect in alkalies and weak bases; are resistant to strong acids, but show variable behavior depending on the specific media for environments containing organic solvents; and have a continuous heat resistance of 150-175°F. Similarly, polyvinylidene fluoride (PVDF) shows no effect in acids or alkalies; is resistant to strong acids and organic solvents; and has a continuous heat resistance of 300°F [7]. Furthermore, any exposure of a plastic in a treated water environment to UV radiation would require plant-specific evaluation. As such, this tool does not include a logic for further evaluation of the effects of aging in a treated water environment on thermoplastics.

3.6.3 Elastomers

Elastomers used in nuclear plant service can include flexible connections and expansion joints, made of rubber, in treated water systems. For a more detailed discussion of the aging effects of typical elastomers used in nuclear plant service, the user of this tool is referred to Chapter 7 of EPRI report 1002950, *Aging Effects for Structures and Structural Components (Structural Tools), Revision 1* [35], which includes exposure to fluids and discusses the resistance of different types of elastomers to water and other solvents.

3.7 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.

3.7.1 NPRDS / EPIX Review

Reported failures of safety-related components and non-safety-related components in treated water systems at Babcock & Wilcox (B&W), Combustion Engineering (CE), 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

As the EPIX search was conducted for Revision 3 of these tools, the above NPRDS search conditions were matched as closely as possible for the EPIX queries. Although the EPIX search conditions are not an exact match for the NPRDS conditions, a conservative approach was taken when determining the appropriate search conditions. There were 5540 and 3388 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.

3.7.1.1 PWR NPRDS / EPIX Data

Table 3-1 NPRDS / EPIX Search Summary for PWR Systems

FAILURE CAUSES	NO. OF ENTRIES	% OF TOTAL*
Packing	2007	44.5%
Gaskets	1659	36.7%
Seals	505	11.2%
Threaded Connections	111	2.5%
Bolting	51	1.1%
Cracked Welds	88	2.0%
Corrosion	28	0.6%
Flow-Accelerated Corrosion	51	1.1%
Stress Corrosion Cracking	4	0.08%
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 was 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 3.7.2, were effective in eliminating the incidents of IGSCC.

2. One of the four 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. Another case of SCC occurred in a Component Cooling Water system piping weld. A pinhole leak in a Safety Injection Accumulator weld at North Anna was determined to be SCC. The last occurrence of SCC was OD cracking of Emergency Core Cooling System piping at St. Lucie.

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, and 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 FAC failures were reported for the feedwater or main steam systems. The few reported cases of FAC 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.

3.7.1.2 BWR NPRDS / EPIX Data

Table 3-2 NPRDS / EPIX Search Summary for BWR Systems

FAILURE CAUSES	NO. OF ENTRIES	% OF TOTAL
Packing	1301	55.8%
Gaskets, O-Rings	379	16.3%
Seals	447	19.2%
Threaded Connections	17	0.73%
Loose/Broken Bolts/Nuts/Screws	44	1.8%
Nipples, Fittings	54	2.3%
Weld Defect/Crack/Failure	28	1.2%
Erosion	15	0.64%
Flow-Accelerated Corrosion	5	0.21%
Corrosion	9	0.39%
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	2	0.09%
Cavitation	1	0.04%
Waterhammer	1	0.04%

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 is 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 FAC 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.

3.7.2 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. Several generic communications regarding degradation on Class 1 systems were also included since their aging mechanisms and their applicability within the bounds of the specific material and environmental conditions are relevant to this report. The documents searched were: Circulars, Bulletins, Information Notices, and Generic Letters. Of these, 57 were considered to be related, either directly or indirectly, to treated water components. These included 1 Circular, 41 Information Notices, 9 IE Bulletins, and 6 Generic Letters. 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 injects borated water to the reactor loops. ASME Section XI inservice inspection rules referenced in the plant technical specification require 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 metal/clad 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 to 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 lines. 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 corrodents 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 85-034 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 tracing 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 (All Revisions): 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 notice 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 the 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 and 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 (Revisions 0 and 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 200°F, which is attributed to inadequate mixing.

IN 92-07: Rapid Flow-Induced Erosion/Corrosion of Feedwater Piping
This IN discusses 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.

IN 99-19: Rupture of the Shell Side of a Feedwater Heater at the Point Beach Nuclear Plant
IN 99-19 alerted licensees to the potential of feedwater heater shell side rupture due to wall thinning. Extraction steam entered the feedwater heater and was deflected by a diffuser plate, impinging the shell wall. Due to substandard steam quality, this lead to thinning of the shell wall via erosion and eventually, shell rupture. It was suggested that an inspection program for feedwater heaters be included in any periodic inspection programs.

IN 01-09: Main Feedwater System Degradation in Safety Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor
This information notice reported an instance of the discovery of main feedwater system wall thinning below allowable limits. Of concern to the NRC is the degradation of non-isolable sections of single-phase ASME Code Class 2 piping inside containment. This thinning is brought on by the flowing single and two-phase fluids in the form of flow-accelerated corrosion (FAC). Licensees were reminded of the importance of maintaining the wall thickness of high energy piping within allowable values.

IN 02-002 (with supplement): Recent Experience with Plugged Steam Generator Tubes
This information notice alerted licensees to potential for a plugged tube to affect the integrity of adjacent tubes. A plugged steam generator tube was severed near the secondary side of the upper tubesheet and damaged four adjacent in-service (i.e., nonplugged) tubes. The preliminary laboratory investigation of the severed tube found signs of high cycle fatigue, ductile failure, and outside-diameter-initiated intergranular attack (IGA). The licensee concluded that the IGA on the outside of the tube might have made it more susceptible to severing and that the plugged tube was probably a factor in the diode effect. In addition, the industry concluded that it was unlikely the once-through steam generator tubes would sever in the lower tubesheet region. Although the phenomenon of diode effect does not appear to be widespread, it may become more frequent as more tubes are plugged and as the length of time plugged tubes are in service increases.

IN 02-021 (with supplement): Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing
This information notice alerted licensees of preliminary indications of axial outside-diameter (OD) cracking of thermally treated Alloy 600 steam generator (SG) tubing. Most steam generators placed into service before the early 1980s used tubing fabricated from mill-annealed Alloy 600. This tubing was found to be susceptible to degradation, including stress corrosion cracking. To reduce susceptibility to stress corrosion cracking, many steam generators placed into service during the 1980s were made of thermally treated Alloy 600 tubing. Operating experience has confirmed the superior corrosion resistance of thermally treated Alloy 600 tubing. Until the recent findings, no known or likely instances of stress corrosion cracking affecting thermally treated Alloy 600 tubing had been reported in the United States. The findings underscore the importance of being alert

during inspections to evidence of possible stress corrosion cracking, regardless of how long the steam generators have been operating.

IN 03-01: Steam Generator Tube Degradation at Diablo Canyon
This information notice alerted licensees of findings from a recent steam generator tube inspection at the Diablo Canyon Power Plant, Unit 2. Several potentially leaking SG tubes were identified and subsequent eddy current testing identified two contributing degradation modes: circumferential primary water stress corrosion cracking (PWSCC) in the U-bend region and axial outside diameter stress corrosion cracking (ODSCC) at the tube-to-tube support plate intersections. The previously described examples of SG tube degradation illustrate the need for maintaining robust steam generator inspection programs. An effective program should sample for degradation based on both operating experience and engineering assessments of potentially susceptible locations and should be able to conservatively predict degradation growth.

IN 04-01: Auxiliary Feedwater Pump Recirculation Line Orifice Fouling
This information notice alerts licensees to a potential common cause failure of auxiliary feedwater pumps because of fouling of pump recirculation line orifices. A multi-stage anti-cavitational trim package in the body of a globe valve is used as a restricting orifice at a site to limit flow in the AFW recirculation lines. This type of flow restrictor used very small channels and holes in each stage combined with a tortuous path to limit flow and prevent cavitation. Post-maintenance surveillance testing of the motor-driven AFW pump at the site revealed a reduced recirculation line flow. Further evaluations observed partial blockage in 24 of the 54 holes in the outmost sleeve of the restricting orifice. No evidence of debris or particles was found during inspection of the piping at the orifice location. The orifice was cleaned, reassembled, reinstalled, and successfully tested. However, further evaluation determined that the potential for orifice plugging, from the safety-related suction source of service water (raw water) was not properly considered in the design process.

IN 04-08: Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds
This information notice was issued to alert licensees to cracking identified in the nozzle-to-cap weld of control (CRD) return line penetrations of a reactor vessel at a boiling water reactor (BWR) site. Alloy 600 CRD return lines are welded to a low-alloy steel reactor vessel with Alloy 82/182 material. As indicated in BWRVIP-49, both Alloy 600 and Alloy 82/182 are potentially susceptible to stress corrosion cracking (SCC) under normal water chemistry conditions in the BWR environment. Alloy 600 and Alloy 82, due to its higher chromium and lower carbon content, are more resistant to SCC than Alloy 182. Whereas SCC of the base material (nickel-base alloy) is commonly referred to as intergranular SCC (IGSCC), SCC of the weld material is referred to as interdendritic SCC (IDSCC) because of the nature of the elongated grains (or dendrites) in the weld. Both degradation mechanisms refer to essentially the same phenomenon in the base metal and weld metal.

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

BL 76-04 addressed 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 (Revisions 0, 1, 2): Cracking in Feedwater System Piping

Cracking of feedwater nozzle-to-pipe welding zones was 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).

BL 03-01: Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors
The purpose of this bulletin is to inform licensees of the results of NRC-sponsored research identifying the potential susceptibility of pressurized water reactor (PWR) recirculation sump screens to debris blockage in the event of a high-energy line break (HELB) requiring recirculation operation of the emergency core cooling system (ECCS) or containment spray system (CSS) and the potential for additional adverse effects due to debris blockage of flowpaths necessary for ECCS and CSS recirculation and containment drainage. In the event of a HELB within the containment of a PWR, energetic pressure waves and fluid jets would impinge upon materials in the vicinity of the break, such as thermal insulation, coatings, and concrete, causing damage and generating debris. Debris could also be generated through secondary mechanisms, such as severe post-accident temperature and humidity conditions, flooding of the lower containment, and the impact of containment spray droplets. Through transport methods such as entrainment in the steam/water flows issuing from the break and in containment spray washdown, a fraction of the generated debris and foreign material in the containment would be transported to the pool of water formed on the containment floor. If the ECCS or CSS pumps subsequently took suction from the recirculation sump, the debris suspended in the containment pool would begin to accumulate on the sump screen. The accumulation of this suspended debris on the sump screen could create a roughly uniform mat over the entire screen surface, referred to as a debris bed, which would tend to increase the head loss across the screen through a filtering action. If a sufficient amount of debris accumulated, the debris bed would reach a critical thickness at which the head loss across it would exceed the net positive suction head (NPSH) margin required to ensure the successful operation of the ECCS and CSS pumps in the recirculation mode. A loss of NPSH margin for the ECCS or CSS pumps as a result of the accumulation of debris on the recirculation sump screen, referred to as sump clogging, could result in degraded pump performance and eventual pump failure.

Previously issued generic communications of this subject are (description not provided in this report):

- BL 93-02: Debris Plugging of Emergency Core Cooling Suction Strainers
- BL 95-02: Unexpected Clogging of a Residual Heat Removal (RHR) Pump Strainer While Operating in Suppression Pool Cooling Mode
- BL 96-03: Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors
- GL 98-04: Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

BL 04-01: Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors
The purpose of this bulletin is to advise licensees that additional measures may be needed to detect and adequately characterize primary water stress corrosion cracking (PWSCC) of nickel-base alloy materials. The bulletin also summarizes, including the identification of previous generic communications, operating experience with PWSCC of nickel-base alloys (e.g., 600/82/182). Furthermore, recent evidence of circumferential cracking of non-pressure boundary portion of pressurizer heater sleeves at a U.S. site challenges the assumption that PWSCC will always be axially oriented. Based on NRC experience with the evolution of PWSCC degradation in other parts of the reactor coolant pressure boundary, evidence of circumferential PWSCC at a given location has usually been observed after axial PWSCC at the location was discovered.

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 lines 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 200°F 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 200°F 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.

GL 96-04: Boraflex Degradation in Spent Fuel Pool Storage Racks
The purpose of this generic letter is to request licensees that use Boraflex as a neutron absorber in their spent fuel storage racks to assess the capability of the Boraflex to maintain a 5-percent subcriticality margin, and submit to the NRC a plan describing their proposed actions if this subcriticality margin cannot be maintained because of current or projected future Boraflex degradation. Experimental data from test programs, including blackness tests performed at various boiling-water reactor (BWR) and pressurized-water reactor (PWR) spent fuel storage pools, confirmed that when Boraflex is exposed to gamma radiation, the material may shrink by as much as 3 to 4 percent. Data from laboratory tests and spent fuel pool silica measurements have identified a second factor that could affect storage rack service life, i.e., the potential gradual release of silica from Boraflex following gamma irradiation and long-term exposure to the wet pool environment. When Boraflex is subjected to gamma radiation in the pool aqueous environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released. The loss of boron carbide from Boraflex is characterized by slow dissolution of the Boraflex matrix from the surface of the Boraflex and a gradual thinning of the material. The boron carbide loss can result in a significant increase in the reactivity of the storage racks. An additional consideration is the potential for silica transfer through the fuel transfer canal into the reactor core during refueling operations and its effect on the fuel clad heat transfer capability.

Summary
A review of NRC generic correspondence shows that a majority of the operating history failures are discussing wall thinning as a result of FAC 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.

3.8 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." Programs that are credited with managing aging predominantly focus on these "effects," not on the aging mechanisms themselves. Any such programs should be evaluated on a plant-specific basis as described in Section 4.0 of the main document, outside the scope of this tool, to demonstrate their effectiveness.

4. FLOW DIAGRAM AND SUMMARY TABLE 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 4.0 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. Thresholds for oxygen, chlorides, fluorides, and sulfates are provided for information. Aging effects shown as not a concern based on water chemistry are considered applicable aging effects that require management. The chemistry program is the aging management program managing those effects. 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 or contaminants such as chlorides are sufficient to sustain 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. As described in Section 3.2.2, IGA is distinguished from SCC in that stress is not required for it to proceed. By assuming stresses sufficient for SCC, the logic paths for IGA initiation are encompassed by the SCC logic. Additionally, the aging effects of IGA and SCC are similar. Therefore, the tool logic does not differentiate between the IGA and SCC.

7. Stress corrosion cracking, including primary water stress corrosion cracking (PWSCC), of non-Class 1 nickel-base alloys is not a significant aging 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 applicant 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.

13. Stress corrosion cracking (SCC) of austenitic stainless steels is not a significant aging mechanism below 140°F.

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 aging effects for plant equipment 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, as described in Section 4.0 of the main document.

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

Tables 4-1, 4-2, and 4-3 (added in Revision 3) identify applicable aging effects that may require programmatic oversight for the period of extended operation. These tables summarize the information depicted on the flow diagrams (Figure 1-Figure 4) and are organized to first address aging effects common to the materials covered by the table and then those that are specific to a material. The list of potential aging effects, together with the detailed mechanism discussions in Section 3.0 and assumptions in Section 4.1 of this appendix, provides the basis for development of the treated water 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 applicable cracking and loss of material aging effects for stainless steel and nickel-base alloy materials. The aging mechanisms covered by this logic branch include crevice corrosion, pitting corrosion, caustic corrosion, SCC (also CSCC), and IGA. 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. SCC, including PWSCC, of nickel-base alloys is not applicable at temperatures below 500°F. The second branch on Figure 1 provides the logic to determine whether reduction of fracture toughness resulting from thermal embrittlement is plausible. The last branch questions the potential for MIC by contamination in the treated water systems. Figure 2 addresses all applicable aging mechanisms for titanium and titanium alloys, including caustic corrosion, crevice corrosion, MIC, SCC (as well as CSCC), and IGA.

The logic for the treated water/carbon, low-alloy steel, and cast iron tool is provided in Figure 3. The applicable aging effects include loss of material because of general corrosion, pitting, crevice corrosion, caustic corrosion, erosion, FAC, galvanic corrosion, and MIC (and related nitrate induced cracking); and loss of material due to the selective leaching of gray cast iron.

The logic for the treated water/copper and copper alloys and aluminum and aluminum alloys tool is provided in Figure 4. The applicable aging effects include loss of material because of selective leaching, galvanic corrosion, pitting/crevice corrosion, erosion, and MIC; and cracking because of SCC and IGA. Copper and its alloys and aluminum and its alloys are not typically used in caustic service.

4.4 GALL Comparison

The information in Chapters IV, V, VII, and VIII of Volume 2 of NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results," identifies material, environment(s), typical aging effects (and associated mechanisms), and suggested aging management programs (AMP) for various mechanical components. GALL Chapters V, VII, and VIII tables all include items for treated water environments addressed by this tool. GALL Chapter IV (Reactor Vessel, Internals, and Reactor Coolant System) is focused on Class 1 components that are not addressed by this tool, but includes certain items for non-Class 1 mechanical components in a treated water environment. The identification and evaluation of aging management programs (AMPs) is outside the scope of this tool and will be addressed on a plant-specific basis, as described in Section 4.0 of the main document. Pertinent GALL items are addressed in Tables 4-1, 4-2, and 4-3 as applicable, with the following material, environment, aging effect, and aging mechanism considerations.

While component identification is also outside the scope of this tool, the materials for the pertinent items in GALL Chapter IV (Non-Class 1), V, VII, and VIII are consistent with the materials addressed by this tool, which are described in Section 2.1. Stainless steel is referred to as "stainless steel," "cast austenitic stainless steel," and "steel with stainless steel cladding" in the GALL items for environments addressed by this tool. It is also listed with steel (carbon steel) for certain items in Chapter VIII (VIII.E-40, VIII.G-41). Nickel-base alloys are referred to as "nickel-based alloy" in the GALL items for environments addressed by this tool. Carbon or low-alloy steel is referred to as "steel" or "steel with elastomer lining" in the GALL items for environments addressed by this tool. Coatings/linings are not credited with precluding aging effects in this tool. Cast iron is included with "steel" in the GALL items for environments addressed by this tool, except where "gray cast iron" is specifically identified. Copper and copper alloys are referred to as "copper alloy" and "copper alloy > 15% Zn" in the GALL items for environments addressed by this tool. Aluminum and aluminum alloys are referred to as "aluminum" in the GALL items for environments addressed by this tool. The non-metals that are listed in the GALL for environments addressed by this tool include "glass" and "elastomers." Plastics, galvanized steel, and titanium and titanium alloys are not listed in the GALL for the treated water environments addressed by this tool.

The following GALL Chapter IV (Non-Class 1), V, VII, and VIII environments are bounded by the environments addressed in this treated water tool, which are described in Section 2.2:

- Closed cycle cooling water, Closed cycle cooling water >60°C (>140°F)
- Reactor Coolant
- Secondary feedwater, Secondary feedwater/steam
- Sodium pentaborate solution, Sodium pentaborate solution >60°C (>140°F)
- Steam
- Treated borated water, Treated borated water >250°C (>482°F), Treated borated water >60°C (>140°F)
- Treated water, Treated water >250°C (>482°F), Treated water >60°C (>140°F)

The GALL items (V.F-10, V.F-9, VII.J-13, VII.J-12, and VIII.I-8) that address glass in treated water or treated borated water concur with the conclusions of Section 3.6.1 with respect to there being no applicable aging effects. The GALL addresses elastomer linings in treated water environments in Chapter VII (items VII.A3-1 and VII.A4-1) and indicates that they are subject to hardening and loss of strength due to elastomer degradation. Chapter 7 of EPRI report 1002950 [35], referenced in Section 3.6.3 of this tool, addresses the age-related degradation of typical elastomers in nuclear plant service, including change in material properties (e.g., hardening and loss of strength) and cracking.

The aging effects cited in GALL Chapters IV (Non-Class 1), V, VII, and VIII for metals in the treated water environments include loss of material due to general corrosion (steel only), galvanic corrosion, crevice corrosion, pitting corrosion, erosion, and selective leaching (or a combination of the previous), cracking due to stress corrosion cracking and intergranular stress corrosion cracking (or a combination of the previous), loss of fracture toughness due to thermal embrittlement, and wall thinning due to flow-accelerated corrosion. Certain GALL items (V.D1-32 and VII.E1-21) for PWR emergency core cooling and PWR chemical and volume control pump casings cite loss of material due to cladding breach. However, cladding breach is degradation of stainless steel, such as due to cracking or loss of material, discussed above.

The GALL also cites cracking due to cyclic loading of older BWR isolation condenser components (IV.C1-5) and high pressure pumps in a PWR chemical and volume control system (VII.E1-7), as well as cracking due to flow-induced vibration for BWR steam dryers (IV.B1-16). These mechanisms are not addressed in this tool as they are related to specific design considerations and require plant-specific evaluation. GALL Chapter IV also addresses various effects specific to steam generator secondary side components that are not addressed in this tool and require plant-specific evaluation, such as ligament cracking due to corrosion and denting due to corrosion of the support plate. In addition, GALL Chapter IV addresses wear/fretting of steam generator tubes in a treated water environment (secondary feedwater/ steam), but does not otherwise identify wear as an aging mechanism, consistent with Section 3.1.8 of this tool.

The GALL Chapter IV, V, VII, and VIII items that address aging effects for external surfaces, closure bolting, and heat exchangers are addressed separately in Appendix E, Appendix F, and Appendix G, respectively. Likewise, GALL items for fatigue are evaluated separately in Appendix H and are not addressed in this tool.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
Wrought Austenitic Stainless Steel *and* CASS *and* Nickel-Base Alloys	Loss of Material / Crevice Corrosion	1. $O_2 > 100$ ppb	IV.C1-6 V.A-23, V.A-27, V.C-4, V.C-7, V.D1-22, V.D1-30, V.D1-32, V.D2-25, V.D2-28 VII.A2-1, VII.A3-8, VII.A4-11, VII.A4-12, VII.C2-10, VII.E1-17, VII.E1-21, VII.E2-1, VII.E3-15, VII.E4-14 VIII.A-12, VIII.A-13, VIII.B1-1, VIII.B1-3,	Yes	Sections 2.1.1, 2.1.2, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3
	Loss of Material / Pitting Corrosion	1. $O_2 > 100$ ppb *and* 2. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 3. Low flow (< 3 fps)			Sections 2.1.1, 2.1.2, 3.1.5 Assumptions 4.1.1, 4.1.3, 4.1.4 Specified GALL items list crevice and pitting together for stainless steel, steel with stainless steel cladding, steel with elastomers lining, or stainless steel cladding but do not include applicability criteria. GALL item VIII.B1-1 is the only non-PWR steam generator item listing crevice/pitting corrosion of nickel-based alloys. See Appendix G for discussion of non-Class 1 PWR steam generators. Specified GALL items list the environment as treated water, treated borated water, closed cycle cooling water, sodium pentaborate solution, reactor coolant (IV.C1-6), and steam.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
			VIII.B1-4, VIII.B2-2, VIII.C-1, VIII.D1-4, VIII.D2-4, VIII.E-24, VIII.E-29, VIII.E-40, VIII.F-20, VIII.F-23, VIII.G-27, VIII.G-32, VIII.G-41		
Wrought Austenitic Stainless Steel *and* CASS *and* Nickel-Base Alloys (Cont'd)	Cracking / SCC/IGA	1. BWR power production loop.	IV.A1-10, IV.A2-1, IV.A2-5, IV.C1-4, IV.C2-22 V.A-24, V.A-28, V.C-8, V.D1-23, V.D1-31, V.D1-33, V.D2-26, V.D2-29, V.E1-7	Yes	Sections 2.1.1, 2.1.2, 2.2.2, 3.2.2 Assumptions 4.1.1, 4.1.5, 4.1.6
		1a. $O_2 > 100$ ppb *or* 1b. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 2. Temperature > 140°F (stainless steel) Temperature > 500°F (nickel-base alloys)			Sections 2.1.1, 2.1.2, 3.2.2 Assumptions 4.1.1, 4.1.5, 4.1.6, 4.1.7 Specified GALL items cite cracking due to SCC, IGSCC, or a combination for stainless steel in treated water environments above 140°F. Cracking of nickel-based alloy is only identified in GALL for Class 1 or PWR steam generator components that are not addressed by this tool. GALL environments include closed cooling water > 60°C (> 140°F), sodium pentaborate

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
			VII.A3-10, VII.C2-11, VII.E1-20, VII.E2-2, VII.E3-3, VII.E3-13, VII.E3-16, VII.E3-19, VII.E4-11, VII.E4-15 VIII.A-10, VIII.A-11, VIII.B1-5, VIII.B1-2, VIII.B2-1, VIII.C-2, VIII.D1-5, VIII.E-25, VIII.E-30, VIII.E-31, VIII.E-38, VIII.F-21, VIII.F-24, VIII.G-28, VIII.G-33		solution > 60°C (> 140°F), treated borated water > 60°C (> 140°F), treated water > 60°C (> 140°F), reactor coolant (as clarified below), and steam. GALL items IV.A1-10 and IV.A2-5 cite the environment as "Air with reactor coolant leakage (Internal) Reactor coolant." The environment may be a mixture of air and reactor coolant in the reactor vessel flange leak detection line. GALL item IV.A2-1 cites the environment as "Reactor coolant" for the bottom mounted instrumentation guide tube (Westinghouse PWRs). Similarly, GALL item IV.C1-4 cites the environment as "Reactor coolant" for isolation condenser components (older vintage BWRs). While these components may be non-Class 1, the other considerations are such that plant-specific review is required.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Wrought Austenitic Stainless Steel *and* CASS *and* Nickel-Base Alloys *and* Titanium and Titanium Alloys	Loss of Material / MIC	1. Potential for MIC contamination *and* 2. pH < 10.5 *and* temperature < 210˚F Note: Plant-specific conditions and operating experience determine whether potential for MIC contamination exists.	None	No	Sections 2.1.1, 2.1.2, 3.1.7 Assumptions 4.1.1, 4.1.11 GALL does not identify loss of material due to MIC as an aging effect in any treated water environment listed in Section 4.4.
	Loss of Material / Erosion	1. Material is subject to high velocity, constricted flow, or fluid direction change *and* 2. Fluid contains particulates (single phase) or water droplets (two phase flow)	V.D1-14	No	Sections 2.1.1, 3.1.6 Assumption 4.1.1 GALL item cites erosion of stainless steel orifice (miniflow recirculation) in a treated borated water environment, for PWR emergency core cooling systems only. GALL does not address titanium or titanium alloys, or the erosion of nickel-based alloys.
	Loss of Material / Caustic Corrosion	1. NaOH concentration > 50% *and* 2a. Temperature > 200ºF (stainless steels) *or* 2b. Temperature > 210ºF (titanium/titanium alloys)	None	No	Sections 2.1.1, 2.1.6, 3.1.8.3 GALL does not address titanium or titanium alloys and does not address caustic in treated water environments, relative to aging effects/mechanisms.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
Wrought Austenitic Stainless Steel *and* CASS *and* Nickel-Base Alloys *and* Titanium and Titanium Alloys (Cont'd)	Cracking / Caustic Cracking (CSCC)	1. NaOH concentration > 25% *and* 2. Temperature > 212ºF	None	No	Sections 2.1.1, 2.1.6, 3.2.3 GALL does not address titanium or titanium alloys and does not address caustic in treated water environments, relative to aging effects/mechanisms.
Nickel-Base Alloys	Cracking / CSCC	1. Alloy 600 material *and* 2. NaOH concentration > 10% *and* 3. Temperature > 550ºF	None	No	Sections 2.1.2, 3.2.3 GALL does not address caustic in treated water environments, relative to aging effects/mechanisms.
CASS	Reduction in Fracture Toughness / Thermal Embrittlement	1. Temperature > 482˚F	V.D1-16 V.D2-20	Yes	Sections 2.1.1, 2.1.2, 3.3.1 Assumptions 4.1.1, 4.1.8 GALL cites the effect as "loss of fracture toughness/ thermal aging embrittlement." Environment for the GALL items is "Treated water >250°C (>482°F)" and "Treated borated water >250°C (>482°F)" respectively. Other GALL items for this aging effect and environment are Class 1 and not addressed by this tool.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
Titanium and Titanium Alloys	Loss of material / Crevice Corrosion	1. O_2 > 100 ppb *and* 2. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 3a. Temperature > 160°F *or* 3b. pH < 10	None	No	Sections 2.1.6, 3.1.4 Assumptions 4.1.1, 4.1.2 GALL does not address titanium or titanium alloys.
	Cracking / SCC	1. Not ASTM grade 1, 2, 7, 11, or 12 *and* 2. Chlorides > 150 ppb *and* 3a. Alloy contains > 5% Aluminum (Al) *or* 3b. Alloy contains > 0.20% Oxygen (O) *or* 3c. Alloy contains any amount of Tin (Sn).	None	No	Sections 2.1.6, 3.2.2. Assumptions 4.1.1. GALL does not address titanium or titanium alloys.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Carbon Steel *and* Low-Alloy Steel *and* Cast Iron	Loss of Material / General Corrosion	1. Always	IV.C1-6, IV.C2-14 V.C-6, V.C-9, V.D2-33 VII.A3-9, VII.A4-12, VII.C2-14, VII.E3-18, VII.E4-17, VII.F1-20, VII.F2-18, VII.F3-20, VII.F4-16, VII.H2-23 VIII.A-15, VIII.A-16, VIII.B1-8, VIII.B1-11, VIII.B2-3, VIII.B2-6, VIII.C-3, VIII.C-4, VIII.C-6, VIII.C-7, VIII.D1-8,	Yes	Sections 2.1.3, 2.1.4, 3.1.1 Assumption 4.1.1 See pitting corrosion discussion below.
	Loss of Material / Crevice Corrosion	1. $O_2 > 100$ ppb			Sections 2.1.3, 2.1.4, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3 See pitting corrosion discussion below.
	Loss of Material / Pitting Corrosion	1. $O_2 > 100$ ppb *and* 2. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 3. Low flow (< 3 fps)			Sections 2.1.3, 2.1.4, 3.1.5 Assumptions 4.1.1, 4.1.3, 4.1.4 Specified GALL items cite general corrosion together with crevice and pitting corrosion as clarified below: ○ GALL items VIII.B1-8 and VIII.B2-3 cite only crevice and pitting corrosion for steel exposed to steam, whereas items VIII.A-15, VIII.A-16, VIII.C-3, and VIII.C-4 cite general, crevice, and pitting corrosion of steel exposed to steam. ○ GALL items VII.A3-9 and VII.A4-12 cite crevice and pitting only following degradation of an elastomer lining.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
			VIII.D2-7, VIII.E-33, VIII.E-34, VIII.E-40, VIII.F-25, VIII.G-38, VIII.G-41		The GALL items are for "steel" or "steel with an elastomer lining" exposed to closed cycle cooling water, treated water, treated borated water, or steam. GALL Chapter IX indicates "steel" is a broad term that groups carbon, low-alloy, high strength low-alloy steel; cast iron; and gray cast iron.
Carbon Steel *and* Low-Alloy Steel *and* Cast Iron (cont'd)	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series. Note: Treated water environments are conservatively assumed to be an electrolyte. With proper control maintaining low impurities, treated water is a poor electrolyte.	None	No	Sections 2.1.3, 2.1.4, 3.1.3 Assumption 4.1.11 GALL items do not identify galvanic corrosion of steel or cast iron in treated water. See pertinent entry in Table 4-3 below.
	Loss of Material / Flow Accelerated Corrosion (FAC)	1. Single phase >200°F or Two-phase *and* 2. Not dry or superheated steam *and* 3. pH < 9.5 *and* 4. Material chromium content < 1.25% Note: FAC may be applicable for drains, traps, and other potentially high-moisture lines from superheated steam systems. The use of HWC in BWRs may cause the RWCU piping, heater drains, moisture	V.D2-31, V.D2-34 VIII.A-17, VIII.B1-9, VIII.B2-4, VIII.C-5, VIII.D1-9, VIII.D2-8, VIII.E-35, VIII.F-26, VIII.G-39	Yes	Sections 2.1.3, 2.1.4, 3.1.6 Specified GALL items cite 'Wall thinning/ flow-accelerated corrosion' of 'steel' steam and treated water.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
		separator drains, and some of the middle extraction steam lines to be affected by FAC. Systems that meet the criteria but operate less than 2% of plant operating time may be susceptible to FAC if plant operating experience has shown FAC damage.			
Carbon Steel *and* Low-Alloy Steel *and* Cast Iron (Cont'd)	Loss of Material / Erosion	1. Material is subject to high velocity, constricted flow, or fluid direction change *and* 2. Fluid contains particulates (single phase flow) or water droplets (two phase flow)	None	No	Sections 2.1.3, 2.1.4, 3.1.6 Assumption 4.1.9 GALL items cite erosion for steel Class 1 BWR components, which are not addressed by this tool, and certain steam generator secondary side internals exposed to secondary feedwater/steam only. Refer to Appendix G for discussion of non-Class 1 steam generator components.
	Loss of Material / MIC	1. Potential for MIC contamination *and* 2. pH < 10.5 and temperature < 210°F Note: Plant-specific conditions and operating experience determine whether potential for MIC contamination exists.	None	No	Sections 2.1.3, 2.1.4, 3.1.7 Assumptions 4.1.1, 4.1.11 NUREG-1801 does not identify loss of material due to MIC as an aging effect in any treated water environment listed in Section 4.4.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Carbon Steel *and* Low-Alloy Steel *and* Cast Iron (Cont'd)	Loss of Material / Selective Leaching	Material is gray cast iron	V.D1-20 VII.A3-7, VII.A4-10, VII.C2-8, VII.C2-9, VII.E1-14, VII.E3-12, VII.E4-10, VII.F1-18, VII.F2-16, VII.F3-18, VII.F4-14, VII.G-16 VIII.A-8, VIII.E-23, VIII.F-19, VIII.G-26	Yes	Sections 2.1.3, 2.1.4, 3.1.2 Assumption 4.1.1 Specified GALL items identify selective leaching of gray cast iron in treated water and closed cycle cooling water environments.
	Loss of Material / Caustic Corrosion	1a. NaOH concentration > 50% (carbon and low-alloy steel) *or* 1b. NaOH concentration > 70% (cast iron) *and* 2. Temperature > 190°F	None	No	Sections 2.1.3, 2.1.4, 3.1.8.3 GALL does not address impacts of caustic on loss of material in treated water environments.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Section(s), Assumption(s), and Discussion
Carbon Steel and Low-Alloy Steel	Cracking / CSCC	1a. NaOH concentration >10% and < 50% *and* 2a. Temperature > 190°F *or* 1b. NaOH concentration > 50% *and* 2b. Temperature > 150°F	None	No	Sections 2.1.3, 2.1.4, 3.2.3 GALL does not address impacts of caustic on cracking in treated water environments.
	Cracking / SCC	1. Potential for MIC contamination *and* 2. pH < 10.5 *and* temperature < 210°F *and* 3. Nitrite corrosion inhibitor in use. Note: Plant-specific conditions and operating experience determine whether potential for MIC contamination exists. Per EPRI TR-107396, Closed Cooling Water Chemistry Guidelines, nitrate concentrations in the range of 10,000 ppm (byproduct of microbial activity) have been known to result in SCC of steel.	None	No	Sections 2.1.3, 3.1.7, 3.2.2 Assumptions 4.1.1, 4.1.6, 4.1.11 GALL does not address cracking as an aging effect for carbon and low-alloy steel ("steel") in treated water environments.

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys	Loss of Material / Crevice Corrosion	1. $O_2 > 100$ ppb	IV.C2-11 V.A-20, V.B-6, V.D1-17, V.D2-21 VII.A3-5, VII.A4-6, VII.A4-7, VII.C2-4, VII.E1-11, VII.E3-8, VII.E3-9, VII.E4-5, VII.E4-7, VII.F1-15, VII.F2-13, VII.F3-15, VII.F4-11, VII.H1-2, VII.H2-8 VIII.A-5, VIII.E-16, VIII.F-13, VIII.F-15, VIII.G-18	Yes	Sections 2.1.5, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3 See pitting corrosion discussion below
	Loss of Material / Pitting Corrosion	1. $O_2 > 100$ ppb *and* 2. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 3. Stagnant or low flow (< 3 fps) Note: The most pit resistant of the copper alloys are the aluminum bronzes with < 8% Al and the low-zinc (< 15%) brasses.			Sections 2.1.5, 3.1.5 Assumptions 4.1.1, 4.1.3, 4.1.4 Specified GALL items identify galvanic corrosion, together with crevice and pitting corrosion of copper alloys (regardless of Zn / Al content) in closed cycle cooling water and treated water environments, except as clarified below. GALL items VIII.A-5 and VIII.F-15 list only crevice and pitting corrosion of copper alloys in a treated water environment, and do not include galvanic corrosion.
	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series Note: Treated water environments are conservatively assumed to be an electrolyte. With proper control maintaining low impurities, treated water is a poor electrolyte.			Sections 2.1.5, 3.1.3 Assumption 4.1.11

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys (Cont'd)	Loss of Material / Erosion	1. Subject to high velocity, constricted flow, or fluid direction change *and* 2. Fluid contains particulates (single phase flow) or water droplets (two phase flow)	None	No	Sections 2.1.5, 3.1.6 Assumption 4.1.9 GALL items do not address loss of material due to erosion as an aging effect for copper alloys in any treated water environment listed in Section 4.4.
	Loss of Material / MIC	1. Potential for MIC contamination *and* 2. pH < 10.5 and temperature < 210ºF Note: Plant-specific conditions and operating experience determine whether potential for MIC contamination exists.	None	No	Sections 2.1.5, 3.1.7 Assumptions 4.1.1, 4.1.11 NUREG-1801 does not identify loss of material due to MIC as an aging effect in any treated water environment listed in Section 4.4.
	Loss of Material / Flow Accelerated Corrosion (FAC)	1. Subject to high velocity, constricted flow, or fluid direction change *and* 2. Part of main steam, feedwater, condensate, or other system identified in Section 3.1.6 *and* 3. Not dry or superheated steam *and* 4. pH < 9.5 Note: Copper or copper alloys are not typical materials of construction for FAC susceptible systems, since the softer metals are somewhat more susceptible to erosion-corrosion.	None	No	Sections 2.1.5, 3.1.6 GALL does not identify loss of material due to FAC as an aging effect for copper or copper alloys in any treated water environment listed in Section 4.4.

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys (Cont'd)	Loss of Material / Selective Leaching	1. Material is **not** an "inhibited" copper alloy *and* 2. Material is Brass/Bronze with > 15% Zn *or* material is Aluminum Bronze with > 8% Al Note: Inhibited copper alloys contain small amounts of other alloying elements (such as Tin, Arsenic, Antimony)	IV.C2-12 V.A-6, V.A-22, V.B-5, V.B-7, V.D1-3, V.D1-19, V.D2-4, V.D2-23 VII.A3-6, VII.A4-8, VII.A4-9, VII.C2-6, VII.C2-7, VII.E1-13, VII.E1-3, VII.E3-10, VII.E3-11, VII.E4-8, VII.E4-9, VII.F1-9, VII.F1-17, VII.F2-15, VII.F3-9, VII.F3-17, VII.F4-13, VII.H1-4, VII.H2-12 VIII.E-19, VIII.E-21,	Yes	Sections 2.1.5, 3.1.2 Assumption 4.1.1 Specified GALL items cite selective leaching of copper alloys with > 15% Zn in closed-cycle cooling water and treated water environments.

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
			VIII.F-16, VIII.F-18, VIII.G-21, VIII.G-23		
Copper and Copper Alloys (Cont'd)	Cracking / SCC/IGA	1. $O_2 > 100$ ppb *and* 2a. Fluid contains ammonia or ammonium compound(s) *and* 2b. Material is Brass/Bronze > 15% Zn *or* material is Aluminum Bronze > 8% Al *or* 3a. Material is Silicon Bronze *and* 3b. Material is exposed to high pressure steam environment Note: The presence of ammonia or ammonium compounds in the fluid may cause rapid general attack (general corrosion) of susceptible copper alloys.	None	No	Sections 2.1.5, 3.2.2 Assumptions 4.1.1, 4.1.6 GALL does not address cracking of copper or copper alloys in any treated water environment listed in Section 4.4.

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Aluminum and Aluminum Alloys	Loss of Material / Crevice Corrosion	1. $O_2 > 100$ ppb	V.D2-19 VII.A4-5, VII.E3-7, VII.E4-4 VIII.D1-1, VIII.D2-1, VIII.E-15, VIII.F-12, VIII.G-17	Yes	Sections 2.1.7, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3 See pitting corrosion discussion below
	Loss of Material / Pitting Corrosion	1. $O_2 > 100$ ppb *and* 2. Chlorides > 150 ppb *or* fluorides > 150 ppb (PWR) *or* sulfates > 150 ppb *and* 3. Stagnant or low flow (< 3 fps)			Sections 2.1.7, 3.1.5 Assumptions 4.1.1, 4.1.3, 4.1.4 Specified GALL items identify crevice and pitting corrosion of aluminum in treated water environments.
	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series Note: Treated water environments are conservatively assumed to be an electrolyte. With proper control maintaining low impurities, treated water is a poor electrolyte.	None	No	Sections 2.1.7, 3.1.3 Assumption 4.1.11 GALL items do not address loss of material due to galvanic corrosion as an aging effect for aluminum (anodic to most metals) in any treated water environment listed in Section 4.4.
	Loss of Material / Erosion	1. Subject to high velocity, constricted flow, or fluid direction change *and* 2. Fluid contains particulates (single phase flow) or water droplets (two phase flow)	None	No	Sections 2.1.7, 3.1.6 Assumption 4.1.9 GALL items do not address loss of material due to erosion as an aging effect for aluminum in any treated water environment listed in Section 4.4.

Table 4-3 Aging Effects Summary - Copper and Copper Alloys and Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Aluminum and Aluminum Alloys (Cont'd)	Loss of Material / MIC	1. Potential for MIC contamination *and* 2. pH < 10.5 and temperature < 210ºF Note: Plant-specific conditions and operating experience determine whether potential for MIC contamination exists.	None	No	Sections 2.1.7, 3.1.7 Assumptions 4.1.1, 4.1.11 GALL does not identify loss of material due to MIC as an aging effect in any treated water environment listed in Section 4.4.
	Loss of Material / Flow Accelerated Corrosion (FAC)	1. Subject to high velocity, constricted flow, or fluid direction change *and* 2. Part of main steam, feedwater, condensate, or other system identified in Section 3.1.6 *and* 3. Not dry or superheated steam *and* 4. pH < 9.5 Note: Aluminum metals are not typical materials for FAC susceptible systems, since softer metals are more susceptible to erosion-corrosion.	None	No	Sections 2.1.7, 3.1.6 GALL does not identify loss of material due to FAC as an aging effect for aluminum alloys in any treated water environment listed in Section 4.4.
Aluminum and Aluminum Alloys (Cont'd)	Cracking / SCC	1. $O_2 > 100$ ppb *and* 2. Chlorides > 150 ppb or fluorides > 150 ppb (PWR) or sulfates > 150 ppb *and* 3. Aluminum alloy contains > 12% Zn or > 6% Mg	None	No	Sections 2.1.7, 3.2.2 Assumptions 4.1.1, 4.1.6 GALL does not address cracking of aluminum or aluminum alloys in any treated water environment listed in Section 4.4.

Figure 1 Treated Water / Stainless Steel and Nickel-Base Alloys

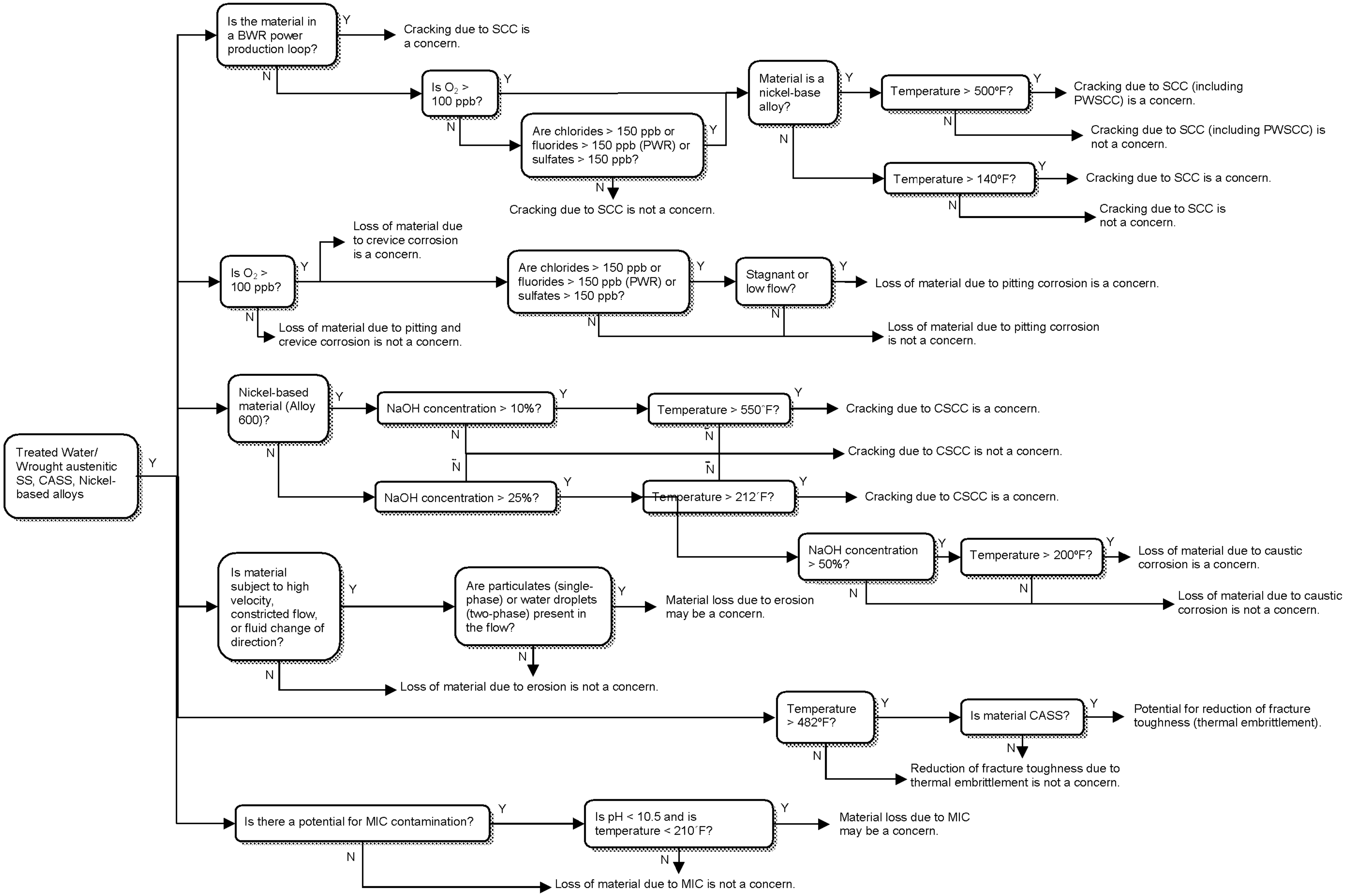


Figure 2 Treated Water / Titanium and Titanium Alloys

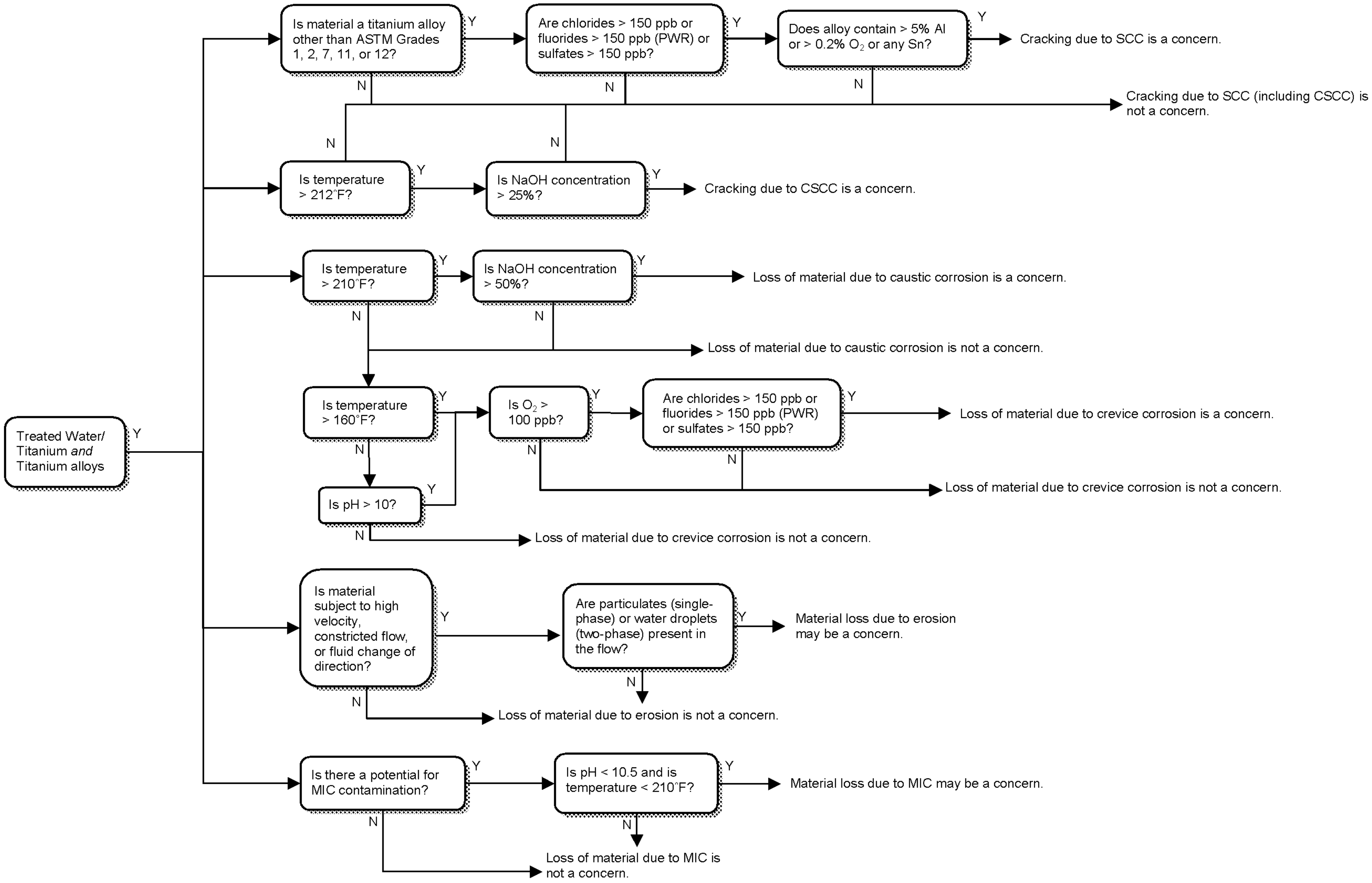


Figure 3 Treated Water / Steam / Carbon Steel, Low-Alloy Steel, and Cast Iron

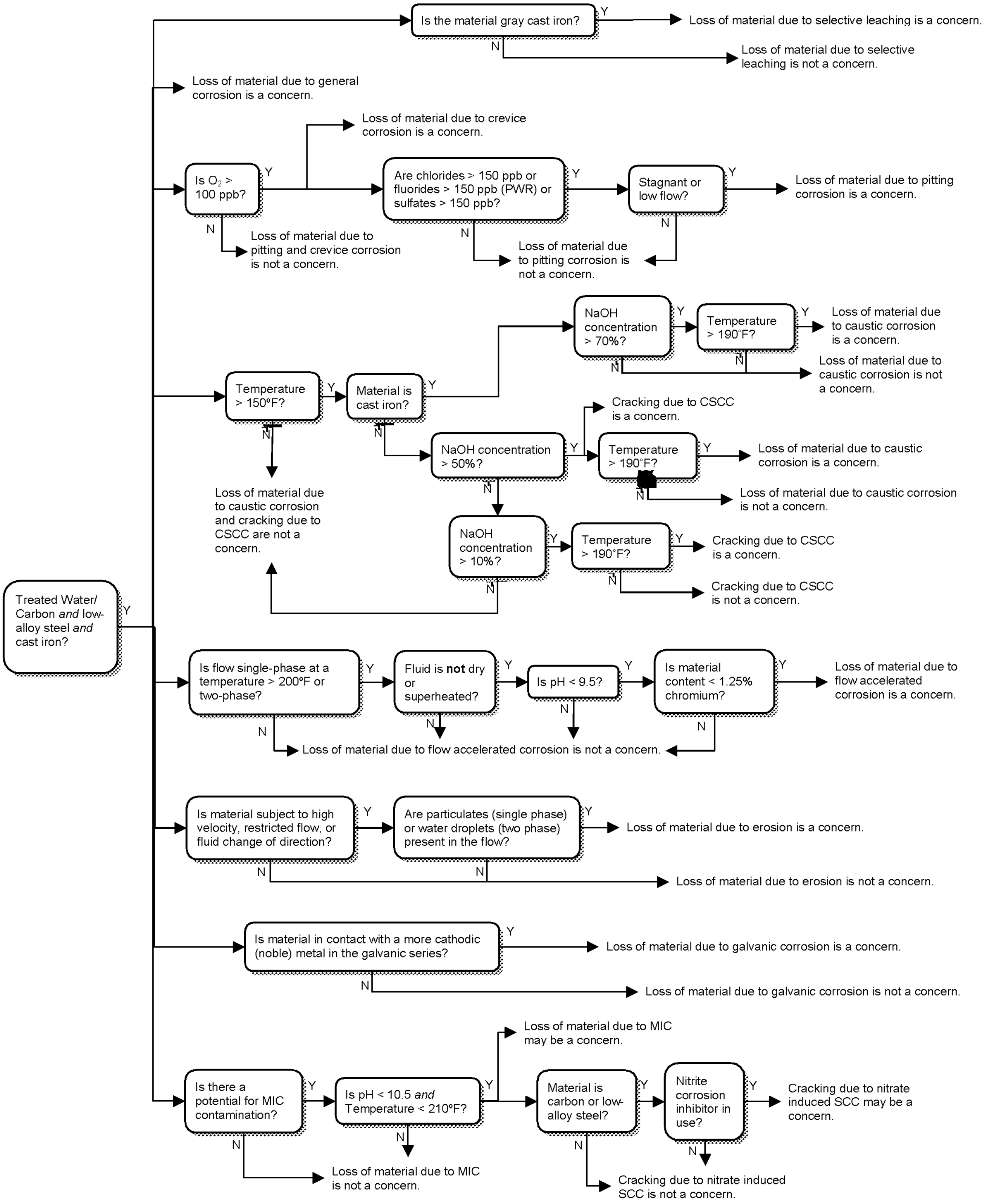
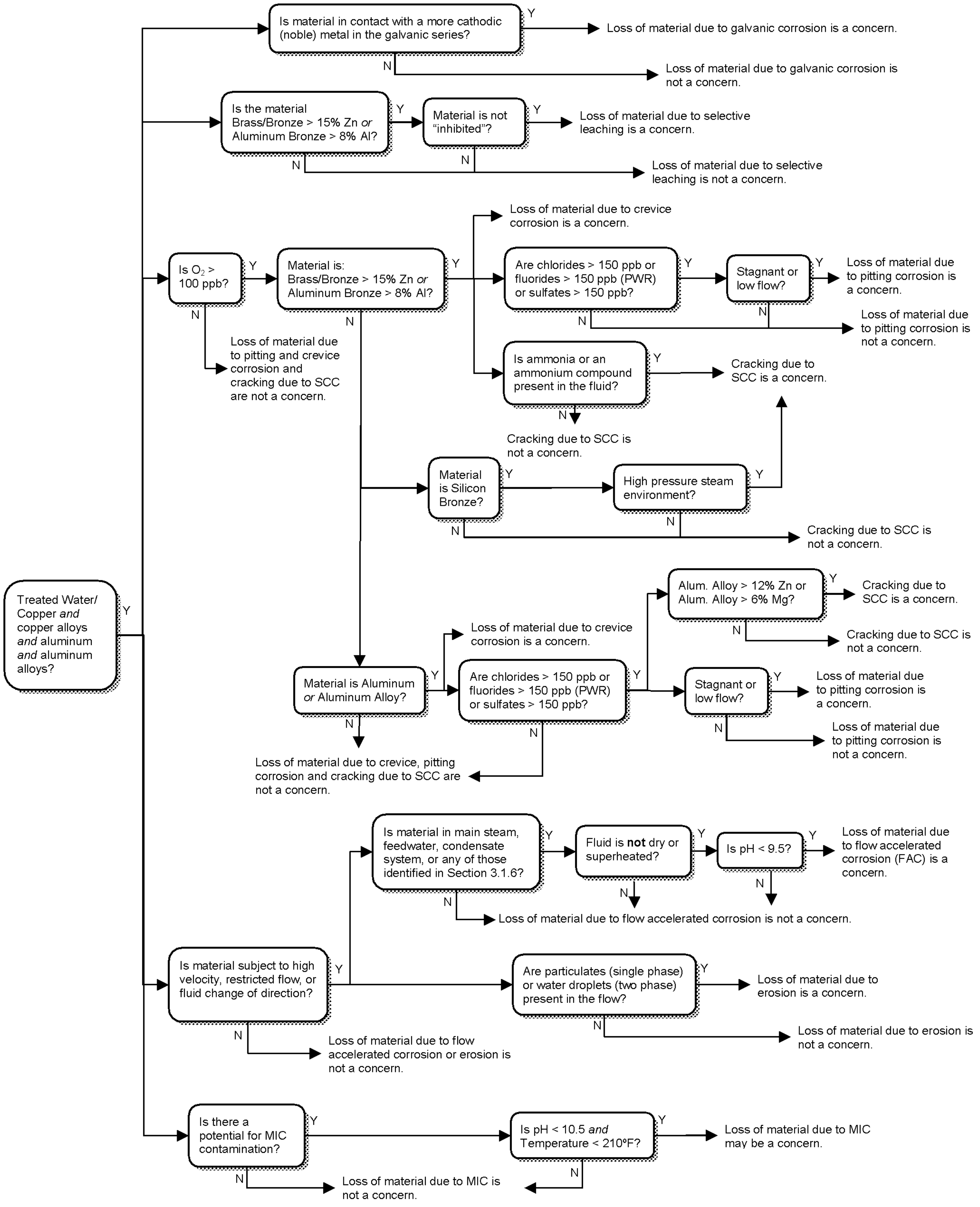


Figure 4 Treated Water / Copper and Copper Alloys and Aluminum and Aluminum Alloys



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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 and that 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, nuclear grade service water system, and the plant fire protection system. Other applications include containment cooling, essential area cooling, component cooling water (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, nickel-base alloys, carbon steel, low-alloy steel, cast iron, copper and copper alloys (brasses, bronzes, copper-nickel), titanium and titanium alloys, aluminum and aluminum alloys, and non-metals such as glass, plastics, and elastomers.

Water that has been previously treated but collects in drains and sumps, potentially with other contaminants, is not chemistry controlled. This untreated water may also be considered to be raw water.

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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. 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. Aging effects considered are loss of material, cracking, change in material properties (e.g., reduction of fracture toughness, distortion), fouling, 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. Aging effects for materials exposed to external environments that are not continuously wetted or in a splash zone are addressed in Appendix E. Evaluation of heat exchangers (and the related loss of heat transfer) is performed with the tool contained in Appendix G. Evaluation of fatigue cracking is addressed with the Fatigue Tool in Appendix H.

This tool primarily addresses the combination of material and internal environment but can also be used to evaluate the combination of material and external environment for components that are submerged, such as in the spray pond (BWR) and intakes. 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, and corresponding summary tables, for the various materials is presented in Section 4.0.

2. MATERIAL AND ENVIRONMENT

This tool provides a logic and methodology where mechanical components subjected to a raw water environment can be evaluated to identify applicable aging effects. These mechanical components are typically in 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. Additionally, treated water potentially mixed with other fluids and/or contaminants in area/equipment drains can be aggressive and is considered to be similar to raw water.

2.1 Materials

The materials evaluated in this tool are: (1) wrought and cast stainless steels, including weld metals and cladding, (2) nickel-base alloys, including nickel-base alloy weld metal, (3) carbon and low-alloy steels, including weld metals, (4) cast irons, (5) copper and copper alloys (brasses, bronzes, copper-nickel), (6) titanium and titanium alloys, (7) aluminum and aluminum alloys, (8) non-metals, and (9) protective coatings.

These materials are identical to those covered by the Treated Water Tool as described in Section 2.1 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. However, a discussion of protective coatings is provided below, which supplements the discussion in Section 2.1.9 of Appendix A.

Protective Coatings

Some of the carbon steel vessels and tanks within the scope of license renewal contain organic protective inner coatings. Other carbon steel, 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. 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.

Failures of linings/coatings have occurred; however, these failures are typically caused by poor original installation (see discussion for IN 85-024 included in Section 3.8.2 of this appendix) or improper maintenance, rather than aging of the linings/coatings. The concern resulting from failure of a lining/coating is aging of the underlying base material where the lining/coating failure has occurred. Whether the failure results from improper maintenance, inadequate installation, or another 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 any linings/coatings credited with preventing degradation of the base material. Furthermore, the joints and seams of concrete-lined piping segments, mentioned above, may without failure allow a small amount of raw water to come in contact with the base material.

As such, this tool does not evaluate the effects of aging on the various coatings and linings, but does evaluate the aging effects which would otherwise result from contact of the base metal with the fluid environment. However, if linings and coatings are credited by a specific plant with managing aging effects, the lining/coating integrity must be assured. When plant programs or inspections are credited with assuring the lining/coating integrity, these programs should be continued through the extended period of operation and included as license renewal "aging management programs" for which a plant-specific demonstration of aging management is to be provided as described in Section 4 of the main document.

2.2 Environment

Raw water consists of all natural sources of raw water, which includes river, lake, brackish, sea and well water as well as potable water (city water) which is not chemistry controlled on-site. Raw water is naturally oxygenated and contains varying amounts of impurities (e.g., chlorides, sulfates). Microorganisms can cause microbiologically influenced corrosion. Most raw water is rough filtered to remove large particles and is generally treated with biocide to control microorganisms and macroorganisms. Hypochlorite is often added to raw water as a biocide, which increases the potential for IGA, SCC, and pitting, galvanic, and crevice corrosion. Water that was previously treated but that collects in drains and sumps, potentially with other contaminants, and is not chemistry controlled is untreated water and may be considered as raw water.

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, change in material properties (e.g., reduction of fracture toughness, distortion), and fouling. Reduction of fracture toughness and distortion are examples of a change in material properties for metals. Other changes in material properties are also discussed, primarily for non-metals. When one or more of the aging mechanisms that could result in the occurrence of an aging effect is determined to be plausible, then the associated aging effects are considered to be applicable for the period of extended operation.

As described in Section 2.2, in many instances liners or coatings are applied to shield materials from various degradation mechanisms. However, this tool considers the effect of the fluid environment on the base material and does not credit the liner or coating for preventing an aging effect.

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 cavitation erosion, and wear (including fretting). The applicability of each aging mechanism is discussed in Sections 3.1.1 through 3.1.8, respectively.

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], and the thinning generally proceeds without appreciable localized attack [13]. 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. Whereas 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 users of this tool 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.

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 at least 12% chromium and titanium/titanium alloys 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 biofouling deposits can produce severe localized attack. This attack is predominantly in the form of crevice/pitting corrosion. Therefore for the purposes of this tool, general corrosion of stainless steels, nickel-base alloys, and titanium and titanium alloys will not be a significant aging mechanism since the dominant failure mode would be from local pitting (or crevice corrosion in the case of titanium) rather than from loss of wall thickness because of uniform general corrosion.

Copper and copper alloys are used when resistance to general corrosion is required. These copper metals are used in atmospheric, fresh and salt water in place of other more susceptible metals such as carbon steel or cast iron [1]. General corrosion of copper and copper alloys results from prolonged contact with environments in which the corrosion rate is very low, such as fresh, brackish, and salt waters. Other substances that cause uniform thinning at a faster rate include oxidizing acids, sulfur-bearing compounds, NH_3, and cyanides. Copper corrodes at negligible rates in unpolluted air, water, and deaerated non-oxidizing acids [13]. Copper exhibits good resistance to urban, marine, and industrial atmospheres and waters. Copper alloys are resistant to neutral and slightly alkaline solutions with the exception of those containing ammonia, which causes stress corrosion (discussed separately) and sometimes rapid general attack [5]. A patina forms on copper and copper alloys from prolonged exposure, which gives the surface a weathered appearance. However, due to the protective film which forms on the surface of copper and copper alloys combined with the very low (negligible) corrosion rates in fresh, brackish, and salt waters, general corrosion is not considered an aging mechanism for copper and copper alloys in a raw water environment. An exception that requires plant-specific evaluation is the presence of ammonia in a raw water environment, in which case the general attack of copper and copper alloys may be rapid and result in a loss of function.

Aluminum and aluminum alloys are reactive metals, but develop an aluminum oxide coating that protects them from corrosion in many environments. This film is quite stable in neutral and many acid solutions but is attacked by alkalies [5]. Aluminum and aluminum alloys are resistant to corrosion by many natural waters. Service experience with wrought aluminum and aluminum alloys in marine (sea water) applications demonstrates their good resistance and long life under conditions of partial, intermittent, or total immersion. Cast aluminum alloys also show high resistance to seawater corrosion. Aluminum alloys that contain copper and are, therefore, least resistant to seawater corrosion are generally not used unprotected. Thinning of aluminum and aluminum alloys exposed to seawater by uniform (general) corrosion is negligible, the rate of corrosion is less than 5% of the rate for unprotected carbon steel in seawater, and corrosion is mainly of the pitting or crevice type. Various correlations of the corrosivity of natural waters to aluminum (and its alloys) have been attempted but none reliably predicts the corrosivity of all natural waters [13]. However, the negligible uniform loss of wall thickness in seawater is considered to be the same or less for natural waters, and the dominant failure mode of aluminum and aluminum alloys is localized rather than uniform. Therefore, for the purposes of this tool general corrosion is not an applicable aging mechanism for aluminum or aluminum alloys that are exposed to 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 and 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 produce 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, titanium or titanium alloys, 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, titanium and titanium alloys, 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 and 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 and its alloys being more cathodic (or passive). When coupled with the more anodic materials such as cast iron or carbon steel, the copper and 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 and copper alloys would demonstrate an increased susceptibility to corrosion [5, 13].

Under most environmental conditions frequently encountered in raw water service, aluminum and its alloys are the anodes in galvanic cells with most other metals, protecting them by corroding sacrificially. Only magnesium and zinc are more anodic. Contact of aluminum with more cathodic metals should be avoided in any environment in which aluminum by itself is subject to pitting corrosion. To minimize the corrosion of aluminum wherever contact with more cathodic metals cannot be avoided, the ratio of exposed surface area of the aluminum to that of the more cathodic metal should be as high as possible to minimize the current density. Corrosion of aluminum (and aluminum alloys) in contact with more cathodic metals is much less severe in solutions of most nonhalide salts, since the aluminum is not normally polarized to its pitting potential, than in solutions of halide salts. Galvanic current between aluminum and another metal also can be reduced by removing oxidizing agents from the electrolyte.

In summary, galvanic corrosion can occur in a corrosive environment (i.e., wetted locations provide an electrolyte) where materials distant on the galvanic series chart are in contact. Corrosion of the material with the lower potential will occur, with the corrosion rate dependent on the difference between the electrochemical potentials of the two materials and the relative size of the anode to the cathode. 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, titanium and titanium alloys, or nickel-base alloys and exposed to raw water (i.e., electrolytically connected) may be susceptible to galvanic corrosion. Copper and copper alloys are also susceptible when coupled to a more cathodic stainless steel, nickel-base alloy, titanium or graphite. Aluminum and aluminum alloys are susceptible if in contact with any of the above materials in the presence of an electrolyte.

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; and 5) using a sacrificial anode—that is, coupling the system to a third metal that is anodic to both 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 [5]. In addition to stagnant conditions in the crevice, an oxygen content in the fluid above 100 ppb is required to initiate 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 or the presence of contaminants such as chlorides 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, aluminum and aluminum alloys, and copper and copper alloys are all susceptible to some degree of crevice corrosion [13].

Titanium and titanium alloys are also susceptible to crevice corrosion although it requires significant aqueous chloride contamination (> 1000 ppm) at elevated temperatures (>160°F) to be subject to this attack [1]. With the exception of titanium and titanium alloys, 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 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. Also notoriously susceptible to attack by crevice corrosion (given a sufficiently narrow crevice in the presence of oxygen) are stainless steels, aluminum or aluminum alloys, and other metals and alloys that depend on oxide films or passive layers for resistance to corrosion [5].

Crevice corrosion of copper and 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]. For most copper and copper alloys, the location of the attack is generally outside the crevice, immediately adjacent the crevice region. 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 sediment (silt), rust, permeable scales, or deposit of corrosion products at the crevice location [13].

3.1.5 Pitting Corrosion

Reactive materials such as titanium exhibit excellent resistance to pitting corrosion. However, pitting corrosion 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].

Another form of pitting corrosion can occur at a gas to fluid interface. This form of corrosion is commonly called water-line attack [13]. Typically, a differential aeration cell is developed at the liquid surface leading to the localized attack just below the water line. All materials susceptible to pitting are susceptible to this type of attack.

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 and 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 and 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 is typically concentrated at surface locations where the protective film has been broken, and where non-protective deposits of sediment, 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 and copper alloys are generally resistant to pitting and crevice corrosion, copper zinc alloys with greater than 15% zinc are susceptible. Aluminum bronze with greater than 8% Al are considered susceptible to pitting in stagnant or low flow conditions.

Aluminum and aluminum alloys are passive (protected by an oxide film) in the pH range of about 4 to 8.5. For aluminum (and aluminum alloys), pitting corrosion is most commonly produced by halide ions, of which chloride is the most frequently encountered in service. In the presence of oxygen, the metal is readily polarized to its pitting potential. In the absence of oxygen or other cathodic reactant, aluminum (and aluminum alloys) will not corrode by pitting because it is not polarized to its pitting potential [13]. Also, ions of several metals can be reduced to metallic form by aluminum. The more important heavy metals are copper, lead, mercury, nickel and tin. Copper is the heavy metal most commonly encountered in applications of aluminum. A copper-ion concentration of 0.02 to 0.05 ppm in neutral or acidic solutions is generally considered to be the threshold value for initiation of pitting on aluminum [13]. Therefore, pitting corrosion is a potential aging mechanism in stagnant or low flow conditions for aluminum and aluminum alloys that contain any amounts of copper, lead, mercury, nickel or tin and are exposed to a raw water environment that is outside the pH range of 4 to 8.5.

3.1.6 Erosion and Cavitation Erosion

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. Piping layouts such as elbows, small radius changes of direction, and branch connections of 90-degrees are most susceptible to flow-induced erosion [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 number of failures clearly a result of 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, impingement, or cavitation. Carbon steel, low-alloy steel, cast iron, wrought austenitic stainless steel, CASS, copper and copper alloys, aluminum and aluminum alloys, and nickel-base alloys are all susceptible to erosion [1, 5, 13].

In normal environments, the hard, tenacious TiO_2 surface film of titanium provides a superb barrier. For this reason, titanium alloys can withstand flowing water and seawater velocities as high as 100 ft/s with insignificant metal loss [13]. Titanium alloys also exhibit relatively high resistance to fluids containing suspended particles [13, 38]. Critical velocities for excessive metal removal depend on the concentration, shape, size, and hardness of suspended particles in addition to fluid impingement angle, local turbulence, and titanium alloy properties. The typical concentrations of particles in seawater are of little consequence, but continuous exposure to high-velocity slurries of hard particles can lead to finite metal removal [13]. As the raw water environments addressed in this tool are not "slurries of hard particles," erosion of titanium and titanium alloys is not considered an applicable aging mechanism when exposed to raw water.

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 orifices 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 120°F, however, microbes can withstand a wide range of temperatures (15 to 210°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 and 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, biofouling, 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°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 0.5 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 system 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 Macrofouling (Biofouling)

Both fresh water and sea water can sustain thousands of types of animal and plant life, including barnacles, mussels, clams, algae, and others. These macro-organisms attach themselves to solid surfaces during their growth cycle, and effectively seal off a small part of the surface from its environment. This is termed fouling, or bio-fouling, and typically occurs within the first 2 or 3 days of exposure to a raw water environment [34]. In terms of corrosion, the impacts of macrofouling are similar to those of microbiologically influenced corrosion (MIC), addressed in Section 3.1.7 above. Discontinuous layers of macroorganisms may induce oxygen or chemical concentration cells that lead to various types of localized corrosion, such as crevice and/or pitting corrosion [5, 31, 34].

Most metals that are susceptible to crevice and pitting corrosion in raw water, as described in Section 3.1.4 and 3.1.5 above, are also susceptible to localized attack by attached macroorganisms. However, aluminum and its alloys do not inhibit the growth of marine organisms but are impervious to worms and borers, and the acids exuded from marine organisms are not corrosive [13]. Copper compounds are toxic to barnacles, mussels, and other macroorganisms [34]. Copper alloys, including the copper-nickels have long been recognized for their inherent resistance to marine fouling. Research demonstrated that fouling was not observed on copper-nickel alloys containing 80% or more copper, and that only incipient fouling was noted on the 70Cu-30Ni alloy [13]. Aluminum bronzes have excellent resistance to brackish water, to clear and polluted sea, and to many types of fresh water, but are subject to biofouling when the water velocity is less than 5 ft/s [34]. Therefore, aluminum and aluminum alloys, copper, and copper alloys with greater than 80% copper are not susceptible to a loss of material due to macrofouling (biofouling), except as noted. Many of the more noble alloys (e.g., stainless steel, nickel-base alloys, etc.) have been known to foul and pit deeply, whereas fouling is generally less on iron than on stainless steel after long exposure periods [34]. However, as velocities reach the range of 3 to 6 ft/s in quiet seawater, macrofouling diminishes and the pitting of the more noble alloys slows and even ceases [34].

Instances of macrofouling typically occur early in the service life of a component, and are corrected well before the end of the initial license period. However, macrofouling is an applicable mechanism for degradation of metals exposed to raw water if there is a potential for recurrence. As such, macrofouling (i.e., localized attack such as crevice and/or pitting corrosion resulting from the attachment and growth of macroorganisms) is considered to be an applicable aging mechanism for carbon steel, cast iron, copper alloys with < 80% Cu or > 8% Al, low-alloy steel, nickel-base alloys, stainless steel, and titanium and titanium alloys if there is a potential for macrofouling in the raw water environment and velocities are less than 5 ft/s.

Fouling, including macrofouling and silting, is evaluated as an aging effect in Section 3.5.

3.1.9 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 cavitation erosion 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.

3.1.9.1 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 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.

3.1.9.2 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.

3.1.10 Exfoliation Corrosion

Exfoliation is a form of localized corrosion that primarily affects aluminum alloys. Corrosion proceeds laterally from the initiation sites on the surface and generally proceeds intergranularly along planes parallel to the surface. The corrosion products that form in the grain boundaries force metal away from the underlying base material, resulting in a layered or flakelike appearance. At least one case affecting 6xxx series magnesium-silicon alloys in fresh water service has been reported [13]. The intensity of exfoliation increases in slightly acidic environments or when the aluminum is coupled to a cathodic dissimilar metal. Exfoliation is not accelerated by stress and does not lead to stress corrosion cracking (SCC) [13]. Exfoliation corrosion is restricted in depth, and therefore does not cause unexpected failure, as does SCC [13], and is not considered to be an applicable mechanism for aluminum and aluminum alloys in raw water environments.

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°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 shows no evidence of hydrogen blistering; therefore, it is considered not applicable for carbon and low-alloy 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 and low-alloy 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 and 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 and copper alloys, including those covered by this tool, are deoxidized and are not susceptible to SCC, except as addressed in Section 3.2.2.

In most cases, austenitic stainless steels are immune to hydrogen damage although nickel-base alloy may be somewhat susceptible [2, 3]. 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.

Only recently has it been determined that hydrogen embrittles aluminum. Hydrogen damage occurs occasionally in aluminum and aluminum alloys, but it is not a significant problem. When a high-strength aluminum alloy is cathodically charged, its ductility is reduced [32]. Since hydrogen damage is not a significant problem for aluminum and aluminum alloys, and the use of aluminum and aluminum alloys is typically limited in nuclear plant raw water environments, hydrogen damage is not considered to be an applicable aging mechanism for aluminum and aluminum alloys exposed to 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. These modes can be mixed or the mode can switch from one to the other.

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. IGSCC is the predominate form of SCC in BWRs. 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.

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 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 and copper alloys, titanium and titanium alloys, and carbon and low-alloy steels, as well as aluminum and aluminum alloys, to SCC or IGA in a raw water environment is provided below.

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. However, silicone bronze is a material that is susceptible to IGA yet is not susceptible to SCC.

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°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 significant chlorides, IGSCC in stainless steel can occur at room temperature [2].

The literature refers to a general rule of thumb for a threshold temperature for the onset of SCC in water of 140°F [13, 25]. Industry data shows 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 and, with a harsh enough environment, SCC can occur in austenitic stainless steel at ambient temperature. However, the probability of failure in water with chloride levels less than 1 ppm is low [18] and 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°F to 2100°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. SCC of nickel-base alloys has been found to occur in types of environments that include high-temperature halogen ion solutions and high-temperature waters. Virtually every nickel-base alloy is susceptible to SCC in chloride solutions if the proper conditions exist. Unlike common stainless steels, the conditions that promote SCC in nickel-base alloys are much more severe. SCC is promoted by various parameters in aqueous halide systems that include the following: elevated temperatures, especially above 400°F; high chloride (Cl^-) contents in the percent range; acidity, usually in the range $pH < 4$; aeration or presence of other oxidizing species [13]. However, it is conservatively assumed that the threshold values of impurities for austenitic stainless steels apply to nickel-base alloys. The high temperature conditions necessary for SCC in nickel-base alloys (e.g., > 400°F) are not experienced in nuclear power plant raw water environments. Therefore, SCC of nickel-base alloys is not an applicable aging mechanism in raw water environments.

SCC of Copper and Copper Alloys

While commercially pure copper is not susceptible to stress corrosion cracking, some copper alloys are susceptible to SCC 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 (NH_3) and ammonium salts. These chemical substances are often 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, as a by-product of MIC (as described in Section 3.1.7), possibly from fertilizers used in certain rural areas. In addition to ammonia or ammonium salts, oxygen and moisture (e.g., an aqueous solution) are required to promote SCC in the copper alloys. Other contaminants such as carbon dioxide may increase the rate of cracking [13, 33].

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 (brass) alloys [3, 5]. These alloys are not considered susceptible to SCC/IGA for this raw water tool. Aluminum bronze (> 8% Al), 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.

As such, even small amounts of ammonia in combination with oxygen and water can cause cracking of certain copper alloys, whereas other alloys are immune. Also, the presence of ammonia or ammonium salts is not generally expected in the raw water environments addressed by this tool. Therefore, SSC/IGA is not an applicable aging mechanism for copper and copper alloys exposed to a raw water environment, unless plant-specific operating experience indicates the presence of ammonia or ammonium salts (such as for pH control, in a cleaning solvent, as a result of organic decay or fertilizers, or as a by-product of MIC). SCC/IGA may be an applicable aging mechanism for certain copper alloys (brasses with > 15% Zn or aluminum-bronzes with > 8% Al) that are exposed to raw water if plant-specific operating experience indicates the presence of ammonia or ammonium salts in the water.

SCC of 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 is in the order of 30 to 45 ksi. Although 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. Nitrate induced SCC of carbon steel in a treated water system can occur with nitrate concentrations around 10,000 ppm, if microbial activity converts nitrite-based corrosion inhibitors, as described in Appendix A. 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.

SCC of Titanium and Titanium Alloys

Grades 1, 2, 7, 11, and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO_3), and liquid cadmium), none of which are applicable in raw water systems. Other titanium and titanium alloys have been found to be susceptible to SCC in additional environments, most notably aqueous chloride solutions. However, this susceptibility is seldom observed in actual field applications [13].

Seawater at ambient temperatures has been known to promote SCC in various titanium alloys, and of unalloyed titanium (with high oxygen content). In addition to the environmental effects, the metallurgical condition of a particular titanium alloy will influence its susceptibility to SCC. In general, titanium alloys with higher aluminum, oxygen, and tin content are the most susceptible to SCC, whereas molybdenum is usually beneficial in increasing SCC resistance. In binary titanium-aluminum alloys, it has been established that 5% Al is necessary for SCC to occur in aqueous environments. Binary titanium-oxygen alloys also exhibit a critical level of oxygen below which SCC does not occur. This level is generally taken as less than 0.20 to 0.25% [13]. For example, alloys containing more than 6% Al are especially susceptible to rapid crack propagation in seawater. Tin, manganese, cobalt, and oxygen have adverse effects, but stabilizers such as molybdenum, niobium, or vanadium reduce or eliminate susceptibility to cracking [33].

Therefore, for the purposes of this tool, SCC of titanium and its alloys is considered an applicable aging mechanism in sea and/or brackish raw water systems if the titanium alloy is not ASTM grade 1, 2, 7, 11, or 12 and contains more than 5% aluminum or more than 0.20% oxygen, or any amount of tin.

SCC of Aluminum and Aluminum Alloys

High-purity and commercially pure aluminum and the relatively low-strength aluminum alloys are not susceptible to SCC [33]. However, aluminum alloys containing more than 12% zinc or more than 6% magnesium are very susceptible to cracking under mild corrosive environments [16]. Only aluminum alloys that contain appreciable amounts of soluble elements (primarily copper, magnesium, silicon, and zinc) are susceptible to SCC. However, for most commercial alloys, tempers have been developed that provide a degree of immunity to SCC in most environments. Research indicates that water or water vapor is the key environmental factor to produce SCC in aluminum alloys. Halide ions (chlorides being the most important) have the greatest effects in accelerating the attack. In general, susceptibility is greater in neutral solutions than in alkaline solutions, and is greater still in acidic solutions. Alloys of the 2xxx, 5xxx, 6xxx, and 7xxx groups of wrought aluminum alloys are susceptible to SCC. Resistance of other wrought alloys and cast alloys, except for 3xx.x and 7xx.x, is sufficiently high that cracking rarely occurs in service [13].

3.2.3 Fatigue

Cracking due to fatigue is discussed in Appendix H.

3.3 Reduction of Fracture Toughness

3.3.1 Hydrogen Embrittlement

With the exception of titanium and titanium alloys, materials in raw water environments are not subject to hydrogen damage/embrittlement as described in Section 3.2.1. Titanium has demonstrated a tendency toward hydrogen embrittlement although a mechanism for the generation of atomic hydrogen must be present. This could include the titanium in contact with a corroding metal (galvanic couple) or an excessive impressed cathodic current. Additionally, the metal temperature must be greater than 175°F and the solution pH must be outside the 3 to 12 range. The dissolved hydrogen reacts to form a brittle hydride compound which results in the loss of ductility and tensile strength [13]. Avoiding any of the above conditions will prevent hydrogen embrittlement of titanium and titanium alloys [13].

3.3.2 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°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.

3.3.3 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 Fouling/Silting

Water-borne deposits, commonly known as foulants, are loose, porous, insoluble materials suspended in water. They include such diverse substances as particulate matter, migrated corrosion products, sediment, etc. Deposits may be organic, inorganic, or a mixture of the two. Scales are crystalline deposits that precipitate in a system. In addition to their impact as a mechanism for corrosion (loss of material) described in Sections 3.1.4, 3.1.5, and 3.1.8, foulants can accumulate in equipment and piping and impede heat transfer or fluid flow [13]. Fouling, as well as silting, may prevent (or impede) the performance of intended functions and is, therefore, considered to be an applicable aging effect for components exposed to raw water. Reduction (loss) of heat transfer, either through flow restriction or the insulating properties of the foulant, is applicable only to heat exchangers and is addressed in Appendix G.

Flow restriction may be an issue for spray and sprinkler nozzles, but is not considered to be an age-related effect. Operating experience has shown that cases of fouling, silting, and/or corrosion product buildup occur well before the end of the initial license period of 40 years. The user of this document should review the latest industry developments with respect to treatment of flow restriction as an aging affect.

3.6 Material Loss/Change in Properties/Cracking – Non-Metals

Non-metals such as glass, plastic (thermoplastic), elastomers, and concrete, that may be used in nuclear power plant raw water systems (such as for sight glasses, flow/level meters, piping, sealants, etc.), exhibit different responses to age-related degradation than do metals. As described in Section 3.6 of Appendix A of these tools, degradation of glasses and thermoplastics in nuclear plant water systems is not expected based on industry operating experience and the assumption of proper material selection and application. Factors related to passive aging that may contribute to the degradation of glass are high temperature water, hydrofluoric acid, and the caustic alkalies [3], none of which are applicable in typical raw water systems. The factors related to passive aging that may contribute to the degradation of thermoplastics (e.g., PVC, PVDF) include ultraviolet (UV) radiation (photooxidation) and chemical degradation through hydrolysis, elevated temperature exposure, and oxidation reactions with a solvent. Certain polymer (plastic) types are more susceptible than others to specific degradation mechanisms, but all polymers can be degraded by a least one mechanism [35]. As such, assuming proper selection for the limited use of plastics in raw water service, the plastic will be resistant by design, and degradation is not expected during the extended operating period.

For additional information on the properties and failure susceptibilities of glass and plastic (thermoplastics and thermosets), the user of this tool is referred to Volume 4, "Ceramics and Glasses," and Volume 2, "Engineering Plastics," of the Engineered Materials Handbook published by ASM International, copyright 1991 and 1988 respectively. Alternatively, the ASM Engineered Materials Handbook is available in a desk edition, copyright 2003 [36].

With respect to concrete-lined piping, the logic of this tool evaluates the effects on the base material of contact with the fluid medium, due to the potential for the piping material to be exposed to some amount of raw water at the seams/joints of piping segments. The aging effects for concrete exposed to raw water are addressed in EPRI report 1002590 (successor to TR-114881), *Aging Effects for Structures and Structural Components (Structural Tools), Revision 1* [37], which can be used for the evaluation of the majority of any concrete-lined piping in raw water service. Aging effects for elastomers exposed to fluids are likewise addressed in the Structural Tools.

3.7 Summary of Potential Aging Effects

The previous sections discuss various potential aging mechanisms and their applicability within the bounds of the specific material and environment combinations covered by this tool. Aging mechanisms that are deemed plausible (i.e., that require evaluation) because conditions exist that exceed established thresholds or where thresholds are not defined are identified as "applicable aging mechanisms" along with the associated "aging effect(s)." The applicable aging effects described in the previous sections for the raw water environments addressed by this tool are categorized as loss of material, cracking, and reduction of fracture toughness.

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, 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, titanium and titanium alloys, and nickel-base alloys have two applicable aging effect categories in a raw water environment: loss of material and cracking. Also, reduction of fracture toughness (due to hydrogen embrittlement) is an applicable aging effect for titanium and titanium alloys. Although resistant to general corrosion and galvanic corrosion, the stainless steels, titanium and titanium alloys, and nickel-base alloys are more susceptible to localized corrosion (i.e., crevice and/or pitting corrosion, MIC, and corrosion in the presence of macroorganisms/silt), particularly in a raw water environment. The stainless steels and nickel-base alloys are more resistant than other materials to erosion but are still considered susceptible to material loss. Additionally, the contaminants present in raw water make cracking due to SCC and IGA an applicable aging effect/mechanism for stainless steels and titanium/titanium alloys.

Copper and copper alloys, and aluminum and aluminum 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, localized corrosion of copper and aluminum 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 "uninhibited" brasses and bronzes with greater than 15% zinc content and in aluminum bronzes with greater than 8% aluminum content. Stress corrosion cracking and IGA are also applicable aging mechanisms in a raw water environment for certain copper alloys, in the presence of ammonia, and for aluminum alloys.

There is a contrast in how 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 as described in Section 4 of the main document. 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.

3.8 Operating History

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

3.8.1 NPRDS / EPIX Review

The operating plant experience databases reviewed were the Nuclear Plant Reliability Data System (NPRDS) and its replacement, the Equipment Performance and Information Exchange System (EPIX). 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 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

As the EPIX search was conducted for Revision 3 of these tools, the above NPRDS search conditions were matched as close as possible for the EPIX queries. Although the EPIX search conditions are not an exact match for the NPRDS conditions, a conservative approach was taken when determining the appropriate search conditions. There were 1448 records meeting the search condition(s) for PWR plants and 937 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 298 for PWRs and 209 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 3-1 and 3-2. The NPRDS / EPIX 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.

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 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 / EPIX 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. The large increase in failures in the late 1990s is a result of a large increase of MIC reported at one plant. 54% of the failures since 1997 can be attributed to MIC at this plant.

Table 3-1 NPRDS / EPIX Search Summary for PWRs

FAILURE CAUSE	NO. OF ENTRIES	% OF TOTAL
Corrosion	131	44%
Erosion	39	13%
MIC	51	17%
Cavitation	11	3.6%
Pitting	10	3.3%
Vibration	2	0.7%
Weld Defect	3	1.0%
Galvanic	2	0.7%
Normal Wear	45	15%
Abnormal Wear	1	0.3%
Unknown	4	1.3%

Figure 1 PWR NPRDS / EPIX Service Water System Failures

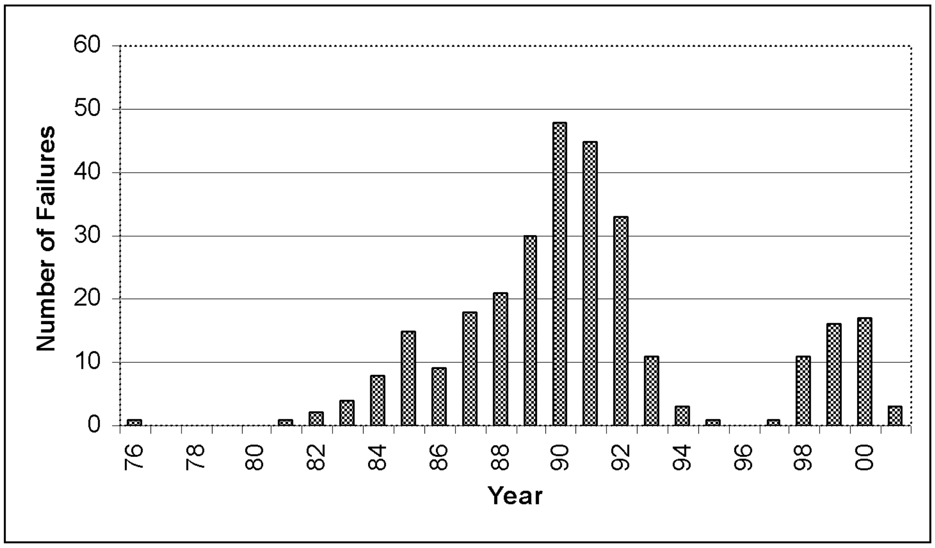
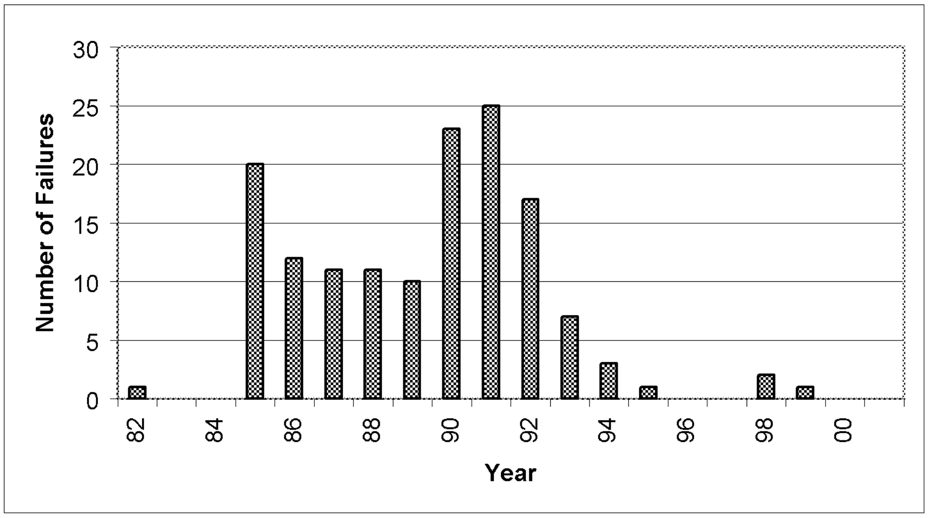


Table 3-2 NPRDS / EPIX Search Summary for BWRs

FAILURE CAUSE	NO. OF ENTRIES	% OF TOTAL
Corrosion	42	20%
Erosion	42	20%
Fittings, Threaded Conn., Nipples	22	11%
Pinhole Leaks	14	6.7%
Pitting	7	3.3%
Weld Cracking	8	3.8%
Galvanic Corrosion	3	1.4%
Cavitation	3	1.4%
MIC	3	1.4%
Bolting	3	1.4%
Waterhammer	1	0.5%
Normal Wear	60	28.7%

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 failures have been reported for that utility since 1991.

2. Twenty of the 39 erosion 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. Remedial action was to apply two coats of ARCOR S-16 epoxy. Prior to 1992, Belzona coating was applied.

3. 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).

4. Prior to 1985, there was only one NPRDS failure reported by BWR raw water systems (one erosion 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.

5. 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).

6. 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.

7. Two of the three 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 / EPIX, 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.

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

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

3.8.2 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, 23 were considered to be related, either directly or indirectly, to the raw water/carbon steel or stainless steel combinations. Eighteen were Information Notices, 2 were IE Bulletins, and 3 were Generic Letters. 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 have 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 mussels 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.

IN 04-001: Auxiliary Feedwater Pump Recirculation Line Orifice Fouling – Potential Common Cause Failure
This information notice alerted licensees of the potential common cause failure of auxiliary feedwater pumps because of fouling of pump recirculation line flow orifices. The recirculation flow restricting orifice (RO) used a multi-stage, anti-cavitation trim package installed in the body of a globe valve to limit flow. This style of orifice or flow restrictor was installed in the AFW recirculation lines to eliminate cavitation caused by the old orifices. This type of flow restrictor used very small channels and holes in each stage combined with a tortuous path to limit flow and

prevent cavitation. A specially fabricated orifice was tested at a contractor laboratory in an effort to determine a plugging probability with service water. Definitive testing occurred when a debris mixture of sand, silt, and zebra mussel shells, representative of what would exist in the Service Water (SW) system, was injected into a closed loop configuration of piping, an orifice, and a centrifugal pump. The orifice plugged in much less than one minute after the mixture was injected into the loop. These results were contrary to those of a previously performed computational particle fouling model analysis that indicated that plugging was unlikely because of the particle size distribution of debris in SW and the shear forces in the holes and channels of the orifices developed with the minimum flow required through the orifice for pump cooling.

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 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.

BL 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

GL 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.

GL 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.

GL 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.

4. FLOW DIAGRAM/SUMMARY TABLE DEVELOPMENT

The following assumptions, overview, respective tool descriptions, and considerations for comparison to the corresponding information in Volume 2 of NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results," 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 and particulates, 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. As described in Section 3.2.2, IGA is distinguished from SCC in that stress is not required for it to proceed. With the assumption of sufficient stress, the logic paths for IGA initiation are encompassed by the SCC logic. Additionally, the aging effects of IGA and SCC are similar. Therefore, this tool logic does not differentiate between IGA and SCC.

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

7. Not used.

8. Stress Corrosion Cracking (SCC) of stainless steels is not a significant aging mechanism below 140°F. Nickel-based alloys are not susceptible to SCC in the typical operating temperature range of raw water systems (since temperatures > 500°F do not exist in raw water systems).

9. Galvanic corrosion can only progress if the dissimilar metals are in contact in the presence of an electrolyte. All materials addressed in these tools are in the presence of an electrolyte (raw water).

10. Although coatings or liners are used in raw water service to prevent contact of the natural/sea waters with the base metal and actions are typically taken to control biological activity in the raw water environments, the ensuing logic diagrams do not assume that the corresponding plant programs are in place, since the programs are not credited in the determination of potential aging effects. Aging effects that would not be a concern based on the use of a coating, liner, biocide or other treatment are considered applicable aging effects that require management.

4.2 Overview

The mechanical tools 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. Utilization of these tools at the various sites will result in the identification of applicable aging effects for plant equipment, based on material and environment combination. These applicable aging effects must be evaluated and managed or justified not to require management 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, as described in Section 4.0 of the main document.

These tools identify potential aging effects and also direct the user to areas in the system where these effects might be preferentially manifested. The age degradation discussions in the previous sections identify numerous aging mechanisms and their associated aging "effects" which can occur in the raw water system equipment addressed by these tools. Figure 3 is the logic diagram to be used in raw water systems for stainless steel, nickel-base alloys, and titanium and titanium 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 and copper alloys, and aluminum and aluminum alloys in a raw water environment. These figures, or alternatively Table 4-1, Table 4-2, and Table 4-3, respectively, 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, titanium and titanium alloy, carbon steel, low-alloy steel, cast iron, copper and copper alloy, and aluminum and aluminum alloy equipment in raw water service. 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. Utilization of the tool, in effect, documents the dispositioning of aging mechanisms and 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 (mechanism applicability) criteria, can be a valuable input when determining how and where aging management programs are used.

4.3 Tool Description

Table 4-1, 4-2, and 4-3 (added in Revision 3) identify applicable aging effects, and corresponding mechanisms, that may require programmatic oversight for the period of extended operation, as well as the applicability criteria for the occurrence and propagation of the mechanisms. These tables summarize the information depicted on the corresponding logic diagrams (Figure 3–Figure 5) and are organized to first address aging effects common to the materials covered by the table and then those that are specific to a material. The potential aging effects, together with the detailed mechanism discussions in Section 3.0 and assumptions in Section 4.1 of this appendix, provide the basis for the development of the raw water tool described below.

4.3.1 Stainless Steel, Titanium and Titanium Alloys, and Nickel-Base Alloys

Figure 3 contains the logic and criteria to evaluate aging effects for the stainless steel, titanium and titanium alloy, 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, crevice/pitting corrosion, and erosion. In addition to the assumptions in Section 4.1, the existence of sensitized stainless steel is assumed in the stainless steel logic. While pitting corrosion is not a concern for titanium or its alloys, crevice corrosion, SCC, and hydrogen embrittlement of titanium and titanium alloys are addressed in the upper branch of Figure 3. This upper branch also discriminates between stagnant and low flow conditions, as pitting corrosion for stainless steel and nickel-base alloys is only a concern in these environments. SCC/IGA of stainless steels is a concern at temperatures greater than 140°F. Erosion of stainless steel 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 next branch addresses the potential for microbiologically induced corrosion (MIC) in a raw water environment. 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.

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 due to selective leaching (also called graphitization) of gray cast iron. Coatings or liners with adequate integrity verification are effective in preventing this mechanism; however, it is incumbent on the user of these tools to demonstrate that the programs in place to verify and maintain the integrity of these coatings or liners are effective as described in Section 4.0 of the main document.

The next branches of Figure 4 address the loss of material effects due to general corrosion, crevice corrosion, and pitting corrosion. 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 fifth branch assumes microorganisms are present in raw water systems and, if the pH is less than 10.5, then material loss due to MIC is a concern. The sixth branch asks whether there is the potential for macrofouling/silting. The seventh branch checks for locations or geometries with high velocities which may increase the potential for erosion.

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 steel or other more noble (cathodic) metals.

4.3.3 Copper and Copper Alloys and Aluminum and Aluminum Alloys

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

The upper branch checks for the possibility of galvanic corrosion at any location where there is electrolytic contact between dissimilar materials. The electrolytic nature of raw water is a given. 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. The second branch addresses the loss of material 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 raw water systems. Stagnant or low flowing conditions are a prerequisite for pitting corrosion, which only affects the identified copper and aluminum 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 branch also addresses the stress corrosion cracking of other aluminum alloys. The fifth branch checks for locations or geometries with high velocities which may increase the potential for erosion.

The sixth branch assumes microorganisms are present in raw water systems and, if the pH is less than 10.5, then material loss due to MIC is a concern. The last branch addresses the potential for loss of material as a result of macroorganisms (macrofouling) and/or silting.

4.4 GALL Comparison

The information in Chapters IV, V, VII, and VIII of Volume 2 of NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results," identifies material, environment(s), aging effects (and associated mechanisms) typically requiring management for license renewal applicants, and the suggested aging management program (AMP) for various mechanical components. GALL Chapters V, VII, and VIII tables all include items for raw water environments addressed by this tool. GALL Chapter IV (Reactor Vessel, Internals, and Reactor Coolant System) is focused on Class 1 components that are not addressed by this tool and does not include raw water environments. The identification and evaluation of aging management programs (AMPs) is outside the scope of this tool and will be addressed on a plant-specific basis, as described in Section 4.0 of the main document. Pertinent GALL items are addressed in Tables 4-1, 4-2, and 4-3 as applicable, with the following material, environment, aging effect, and aging mechanism considerations.

The materials for the pertinent items in GALL Chapters V, VII, and VIII are consistent with the materials addressed by this tool, which are described in Section 2.1. Carbon or low-alloy steel is referred to as "steel" or "steel (with or without lining/coating or with degraded lining/coating)" in the GALL items for environments addressed by this tool. Cast iron is referred to as "gray cast iron" specifically or is otherwise included with "steel" in the GALL, including the items for environments addressed by this tool. Nickel-base alloys are referred to as "nickel alloy," copper and copper alloys are referred to as "copper alloy" or "copper alloy > 15% Zn," and aluminum and aluminum alloys are referred to as "aluminum" in the GALL items for environments addressed by this tool. The non-metals that are listed in the GALL for environments addressed by this tool include "glass" and "elastomers." Plastics, galvanized steel, and titanium and titanium alloys are not listed in the GALL for the raw water environments addressed by this tool.

The GALL Chapters V, VII, and VIII environment of "raw water" is bounded by the environments addressed in this tool, which are described in Section 2.2, as clarified. Chapter IX of the GALL includes untreated water (including originally treated water that is no longer controlled by the Chemistry Program) in floor drains and sumps in its definition of "raw water." However, only item VIII.G-36 (steel exposed to raw water with a plant-specific aging management program) and the items for selective leaching would possibly include drainage/waste water, as the other GALL items cite the open-cycle cooling water program or fire protection program, and these programs are not applicable to drain/sump water.

The GALL items addressing glass in raw water (V.F-8, VII.J-11, and VIII.I-7) concur with the conclusions of Section 3.6 with respect to there being no applicable aging effects. The GALL addresses elastomer seals and components in raw water in Chapter VII. One item (VII.C1-1) indicates that they are subject to hardening and loss of strength due to elastomer degradation. Chapter 7 of EPRI report 1002950 [37], referenced in Section 3.6 of this tool, addresses the age-related degradation of typical elastomers in nuclear plant service, including change in material properties (e.g., hardening and loss of strength) and cracking. The GALL indicates for item(s) in Chapter VII (VII.C1-19, VII.C3-10, VII.H2-22) that steel is evaluated with or without linings/coatings or with degraded linings/coatings, which is consistent with the logic and assumptions of this tool, and also identifies lining or coating degradation as a mechanism for loss of material. GALL item VII.C1-2 lists loss of material due to erosion as an aging effect requiring management for elastomer seals and components, which concurs with the discussion in Section 3.1.6 of this tool, which indicates that linings or coatings are susceptible to damage under conditions of high fluid velocity or flow discontinuities.

The GALL does not evaluate mechanisms separately, as is done in Section 3.0 of this tool. Additionally, the aging mechanisms identified in GALL Chapter V, VII, and VIII are grouped without clear indication as to mechanisms (e.g., MIC and/or fouling) that are indicated as applicable to certain components but not to others. The aging effect cited in GALL Chapters V, VII, and VIII for metals in the raw water environments includes loss of material, with the following groupings of mechanisms depending on material susceptibility:

- General, pitting, crevice, and microbiologically influenced corrosion, and fouling
- General, pitting, crevice, and microbiologically influenced corrosion, fouling, and lining/coating degradation
- Pitting and crevice corrosion
- Pitting and crevice corrosion, and fouling
- Pitting, crevice, and microbiologically influenced corrosion
- Pitting, crevice, and microbiologically influenced corrosion, and fouling
- Selective leaching

Per Chapter IX of GALL, fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling. This categorization is consistent with the discussions in Section 3.1.8 of this tool, with respect to macrofouling (biofouling) and silting as applicable mechanisms for a loss of material in raw water environments.

The GALL does not address cracking, due to SCC/IGA, or reduction of fracture toughness, due to hydrogen embrittlement of titanium and titanium alloys, in raw water environments, whereas they are evaluated in this tool, in Sections 3.2.2 and 3.3.1, respectively. Additionally, the GALL does not identify galvanic corrosion or erosion (of metals) as mechanisms for loss of material in raw water environments. Galvanic corrosion, evaluated in Section 3.1.3, and erosion, evaluated in Section 3.1.6, are applicable mechanisms in this tool.

The GALL Chapter V, VII, and VIII items that address aging effects for external surfaces, closure bolting, and heat exchangers are addressed separately in Appendix E, Appendix F, and Appendix G, respectively. Likewise, GALL items for fatigue are evaluated separately in Appendix H and are not addressed in this tool.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Wrought Austenitic Stainless Steel and CASS *and* Nickel-Base Alloys *and* Titanium and Titanium Alloys	Loss of Material / MIC	1. pH < 10.5	V.C-3, V.D1-25 VII.H2-18 VIII.E-27, VIII.F-22, VIII.G-30	Yes	Sections 2.1, 3.1.7, 4.3.1 Assumption 4.1.6 GALL items are only for stainless steel and also include pitting and crevice corrosion. Additionally, GALL item V.C-3 includes fouling of containment isolation piping/components. GALL does not include any items for titanium or titanium alloys.
	Loss of Material / Macrofouling	1. Potential for macrofouling (mussels, clams, etc.) and/or silting *and* 2. Stagnant, low flow locations (< 3fps freshwater and < 5fps sea/brackish water)	V.C-3 VII.C1-15, VII.G-19	Yes	Sections 2.1, 3.1.8, 4.3.1 GALL items are only for stainless steel, and GALL Chapter V items (containment isolation piping/components) also include pitting and crevice and MIC. GALL Chapter VII items also include pitting and crevice, but not MIC. None of the GALL items address flow velocities or the potential for macrofouling. Also, GALL does not include any items for titanium or titanium alloys.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Wrought Austenitic Stainless Steel and CASS *and* Nickel-Base Alloys	Loss of Material / Crevice Corrosion	1. Always	V.C-3, V.D1-15, V.D1-25 VII.C1-15, VII.C3-6, VII.C3-7, VII.G-19 VII.H2-18 VIII.E-27, VIII.F-22, VIII.G-30	Yes	Sections 2.1, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3
	Loss of Material / Pitting Corrosion	1. Low flow (< 3 fps)			Sections 2.1, 3.1.5 Assumptions 4.1.1, 4.1.2, 4.1.4. Specified GALL items are for stainless steel and nickel alloy (VII.C3-6) exposed to raw water and list both pitting and crevice corrosion, without description of applicability criteria. Item V.C-3 also lists MIC and fouling of stainless steel. Items VII.C1-15 and VII.G-19 also list fouling, but not MIC, as mechanisms for loss of material of stainless steel. Items VII.H2-18, VIII.E-27, VIII.F-22, and VIII.G-30 all list MIC in addition to crevice and pitting as mechanism for stainless steel loss of material, but do not list fouling. This implies that mechanisms are dependent on conditions in a system, but clear indication of what those conditions are is not included in the GALL items.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Wrought Austenitic Stainless Steel and CASS *and* Nickel-Base Alloys *and* Titanium and Titanium Alloys (Cont'd)	Loss of Material / Erosion	1. Component subject to high velocities, constricted flow, or fluid change of direction Note: Though conservatively susceptible to erosion, stainless steel is used as an overlay for its resistance to erosion. Nickel-base alloys, titanium and titanium alloys are considered to have similar characteristics with respect to erosion resistance.	None	No	Sections 2.1, 3.1.6, 4.3.1 Assumption 4.1.2 GALL Chapters V, VII, and VIII do not include erosion as an aging mechanism requiring management for metals in raw water.
Wrought Austenitic Stainless Steel and CASS	Cracking / SCC/IGA	1. Temperature > 140°F Note: Sensitized stainless steel has been known to experience SCC at ambient temperatures (Section 3.2.2).	None	No	Sections 2.1, 3.2.2 Assumptions 4.1.1, 4.1.2, 4.1.5, 4.1.8 GALL Chapters V, VII, and VIII do not include SCC or IGA as an aging mechanism for stainless steel in raw water.

Table 4-1 Aging Effects Summary - Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Section(s), Assumption(s), and Discussion**
Titanium and Titanium Alloys	Loss of Material / Crevice Corrosion	1. Temperature > 160˚F *and* 2. Saltwater or brackish water with pH < 10	None	No	Sections 2.1, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3 Titanium and titanium alloys are not addressed in GALL Chapters V, VII, and VIII.
	Cracking / SCC	1. Not ASTM grade 1, 2, 7, 11, or 12 *and* 2. Salt or brackish water *and* 3a. Alloy contains > 5% Aluminum (Al) *or* 3b. Alloy contains > 0.20% Oxygen (O) *or* 3c. Alloy contains any amount of Tin (Sn).	None	No	Sections 2.1, 3.2.2. Titanium and titanium alloys are not addressed in GALL Chapters V, VII, and VIII.
	Reduction in Fracture Toughness / Hydrogen Embrittlement	1. Temperature > 175˚F *and* 2. pH < 3 or pH > 12 *and* 3. Atomic hydrogen present (galvanic couple, impressed cathodic current)	None	No	Sections 2.1, 3.3.1 Titanium and Titanium alloys are not addressed in GALL Chapters V, VII, and VIII.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Carbon Steel and Low-Alloy Steel *and* Cast Iron	Loss of Material / General Corrosion	1. Always	V.C-5 VII.C1-19, VII.C3-10, VII.H2-22, VII.G-24 VIII.G-36	Yes	Sections 2.1, 3.1.1 Assumption 4.1.1, 4.1.2
	Loss of Material / Crevice Corrosion	1. Always			Sections 2.1, 3.1.4, 3.5 Assumptions 4.1.1, 4.1.2, 4.1.3
	Loss of Material / Pitting Corrosion	1. Low flow (< 3 fps)			Sections 2.1, 3.1.5 Assumptions 4.1.1, 4.1.2, 4.1.4 GALL items cite general, pitting, crevice, and MIC, and fouling as mechanisms for loss of material of steel in raw water. As used in GALL, steel includes both carbon steel, low-alloy steel, and cast iron. GALL items VII.C1-19, VII.C3-10, and VII.H2-22 address degradation of steel with coating/linings or with degraded coatings/linings.
	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1, 3.1.3 GALL Chapters V, VII, and VIII do not include galvanic corrosion as an aging mechanism for loss of material in raw water.

Table 4-2 Aging Effects Summary - Carbon Steel, Low-Alloy Steel, and Cast Iron

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Carbon Steel and Low-Alloy Steel *and* Cast Iron (Cont'd)	Loss of Material / Erosion	1. Subject to high velocity, constricted flow, or fluid direction change Note: Elastomer linings or coatings subject to the same conditions are also subject to erosion (Section 3.1.6).	VII.C1-2	No	Sections 2.1, 3.1.6 Assumption 4.1.2 GALL Chapters V, VII, and VIII do not include erosion as an aging mechanism for loss of material of metals in raw water. Item VII.C1-2 cites erosion as an aging mechanism for loss of elastomer (e.g., linings/coatings) material.
	Loss of Material / MIC	1. pH < 10.5	V.C-5 VII.C1-19, VII.C3-10, VII.G-34, VII.H2-22 VIII.G-36	Yes	Sections 2.1, 3.1.7 Assumptions 4.1.6 See above discussion for pitting corrosion.
	Loss of Material / Macrofouling	1. Potential for macrofouling (mussels, clams, etc.) and/or silting *and* 2. Stagnant, low flow locations (< 3fps freshwater and < 5fps sea/brackish water)			Sections 2.1, 3.1.8 See above discussion for pitting corrosion. Specified GALL items do not include applicability criteria for fouling (e.g., stagnant/low flow).
Cast Iron	Loss of Material / Selective Leaching	1. Material is gray cast iron	VII.C1-11, VII.C3-4, VII.G-14, VII.H2-14 VIII.A-7, VIII.G-24	Yes	Sections 2.1, 3.1.2 Assumptions 4.1.1, 4.1.2 Specified GALL items identify selective leaching as an aging mechanism for gray cast iron in raw water.

Table 4-3 Aging Effects Summary – Copper and Copper Alloys, Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys	Loss of Material / Crevice Corrosion	1. Always	VII.C1-9, VII.C3-2, VII.G-12, VII.H2-11 VIII.A-4, VIII.E-18, VIII.F-14, VIII.G-20	Yes	Sections 2.1, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3
	Loss of Material / Pitting Corrosion	1. Stagnant or low flow (< 3 fps)			Sections 2.1, 3.1.5 Assumptions 4.1.1, 4.1.2, 4.1.4 GALL Chapter V, VII, and VIII items include only copper alloy or do not distinguish between copper (commercially pure) and copper alloys. GALL item VII.C1-9 lists crevice and pitting corrosion. GALL items VII.C3-2, VII.G-12 also cite MIC and fouling as mechanisms for loss of material for copper alloys. GALL items VII.H2-11, VIII.E-18, VIII.F-14, and VIII.G-20 also cite MIC as a mechanism for loss of material, but do not list fouling (macrofouling in this tool). GALL items do not provide mechanism applicability criteria and the listing of mechanisms (e.g., fouling and MIC) for certain copper alloy items but not for others implies that the occurrence has something to do with the particular system.

Table 4-3 Aging Effects Summary – Copper and Copper Alloys, Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys (Cont'd)	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series Note: Copper and copper alloys are cathodic to carbon steel, low-alloy steel and cast iron; and anodic to stainless steel, nickel-base alloys, and titanium and titanium alloys.	None	No	Sections 2.1, 3.1.3 GALL Chapters V, VII, and VIII do not include galvanic corrosion as an aging mechanism in raw water.
	Loss of Material / Erosion	1. Subject to high velocity, constricted flow, or fluid direction change	None	No	Sections 2.1, 3.1.6 Assumption 4.1.2 GALL Chapters V, VII, and VIII do not include erosion as an aging mechanism in raw water.
	Loss of Material / MIC	1. pH < 10.5	VII.C3-2, VII.G-12, VII.H2-11 VIII.A-4, VIII.E-18, VIII.F-14, VIII.G-20	Yes	Sections 2.1, 3.1.7 Assumptions 4.1.1, 4.1.6 See above discussion for pitting corrosion.
	Loss of Material / Macrofouling	1. Potential for macrofouling (mussels, clams, etc.) or silting *and* 2. Material is Copper alloy with <80% Cu or > 8% Al *and* 3. Stagnant or low flow (< 3fps in freshwater and < 5 fps in sea or brackish water			Sections 2.1, 3.1.4, 3.1.8 See above discussion for pitting corrosion. GALL items VII.C1-9 and VII.G-12 do not include applicability criteria for fouling (e.g., stagnant/low flow). Other specified items do not list fouling.

Table 4-3 Aging Effects Summary – Copper and Copper Alloys, Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys (Cont'd)	Cracking / SCC/IGA	1. Fluid contains ammonia or ammonium salts *and* 2. Material is Brass/Bronze with > 15% Zn *or* material is Aluminum Bronze with > 8% Al. Note: Ammonia (NH_3) or ammonium salt may be present in the fluid such as for pH control, in a cleaning solvent, from organic decay, or as a result of MIC.	None	No	Sections 2.1, 3.2.2 Assumptions 4.1.1, 4.1.5 GALL Chapters V, VII, and VIII do not include SCC/IGA as an aging mechanism for copper alloys in raw water. SCC/IGA in the identified copper alloys is only a potential for sites whose operating experience shows amounts of ammonia or an ammonium salt in raw water.
	Loss of Material / General Corrosion	1. Fluid contains ammonia or ammonium salts *and* 2. Material is Brass/Bronze with > 15% Zn *or* material is Aluminum Bronze with > 8% Al. Note: Ammonia (NH_3) or ammonium salt may be present in the fluid such as for pH control, in a cleaning solvent, from organic decay, or as a result of MIC.	None	No	Section 2.1, 3.1.1, and 3.2.2 GALL Chapters V, VII, and VIII do not address general corrosion of copper and copper alloys.

Table 4-3 Aging Effects Summary – Copper and Copper Alloys, Aluminum and Aluminum Alloys

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Copper and Copper Alloys (Cont'd)	Loss of material / Selective leaching	1. Material is not an "inhibited" copper alloy *and* 2. Material is Brass/Bronze with > 15% Zn *or* Aluminum Bronze with > 8% Al Note: Small amounts of alloying elements such as tin, phosphorous, arsenic and antimony inhibit dezincification, but may reduce resistance to SCC, in copper alloys.	VII.C1-10, VII.C3-3, VII.G-13, VII.H2-13 VIII.A-6, VIII.E-20, VIII.F-17, VIII.G-22	Yes	Sections 2.1.5, 3.1.2 Assumption 4.1.1 Specified GALL items list selective leaching of "Copper alloy > 15% Zn" in raw water. Items do not consider the aluminum content or whether the alloy is inhibited.
Aluminum and Aluminum Alloys	Loss of Material / Crevice Corrosion	1. Always	VII.G-8	Yes	Sections 2.1, 3.1.4 Assumptions 4.1.1, 4.1.2, 4.1.3
	Loss of Material / Pitting Corrosion	2. Stagnant or low flow (< 3 fps)			Sections 2.1, 3.1.5 Assumptions 4.1.1, 4.1.2, 4.1.4 Specified GALL item cites crevice and pitting corrosion of aluminum (does not distinguish between commercially pure aluminum and aluminum alloys).
	Loss of Material / Galvanic Corrosion	1. Contact with a more cathodic (noble) metal in the galvanic series Note: Aluminum and aluminum alloys are anodic to all metals addressed by this tool.	None	No	Sections 2.1, 3.1.3 GALL Chapters V, VII, and VIII do not include galvanic corrosion as an aging mechanism in raw water.

Table 4-3 Aging Effects Summary – Copper and Copper Alloys, Aluminum and Aluminum Alloys					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Aluminum and Aluminum Alloys (Cont'd)	Loss of Material / Erosion	1. Subject to high velocity, constricted flow, or fluid direction change	None	No	Sections 2.1, 3.1.6 Assumption 4.1.2 GALL Chapters V, VII, and VIII do not include erosion as an aging mechanism in raw water.
	Loss of Material / MIC	1. pH < 10.5	None	No	Sections 2.1, 3.1.7 Assumptions 4.1.1, 4.1.6 GALL Chapters V, VII, and VIII do not include MIC as an aging mechanism for loss of aluminum material in raw water.
	Cracking / SCC/IGA	1. Material is aluminum alloy with >12% Zn or 6% Mg and/or >1% Cu	None	No	Sections 2.1, 3.2.2 Assumptions 4.1.1, 4.1.5 GALL Chapters V, VII, and VIII do not include SCC/IGA as an aging mechanism for cracking of aluminum in raw water.

Figure 3 Raw Water / Stainless Steel, Nickel-Base Alloys, and Titanium and Titanium Alloys Tool

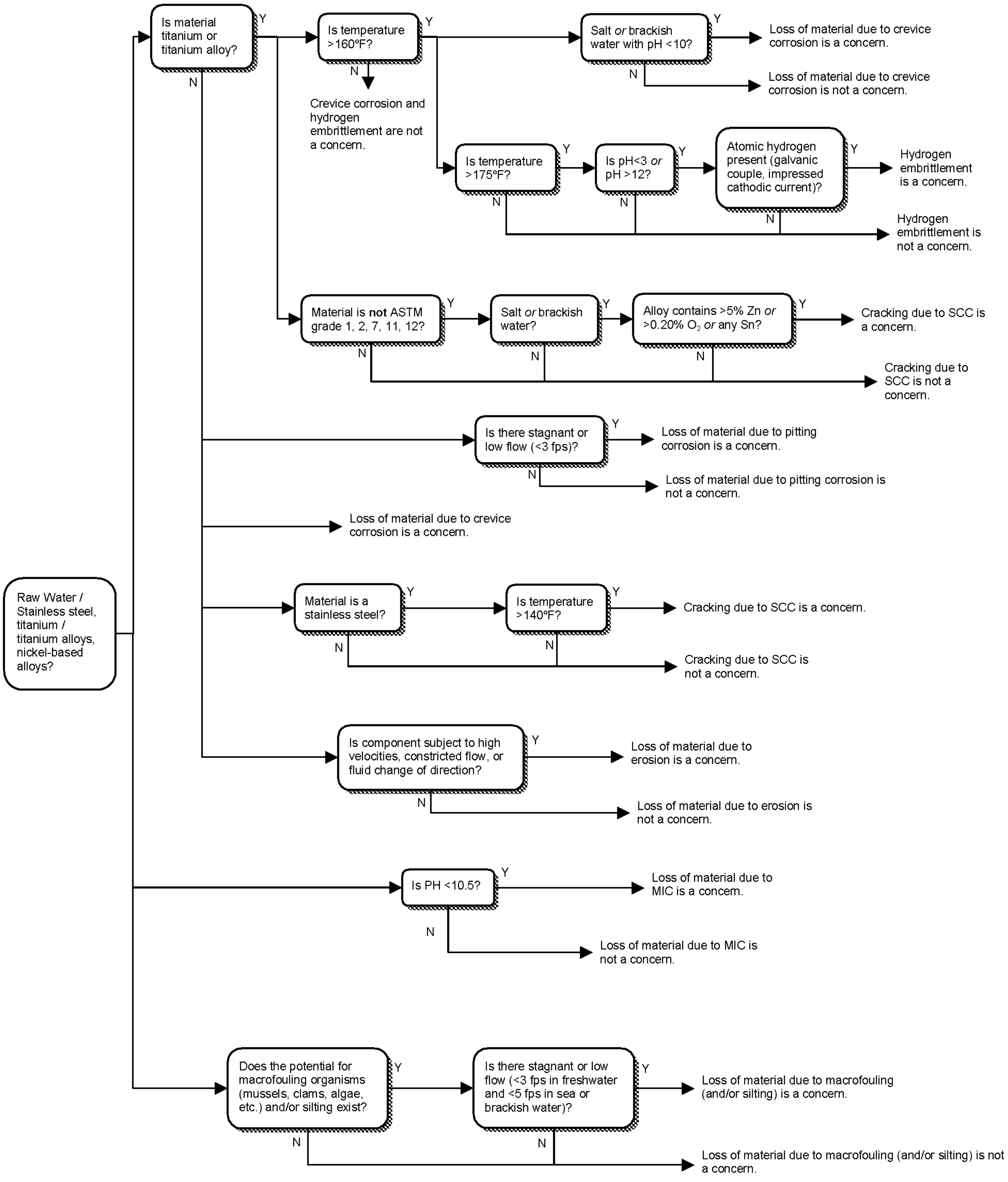


Figure 4 Raw Water / Carbon Steel, Low-Alloy Steel, and Cast Iron Tool

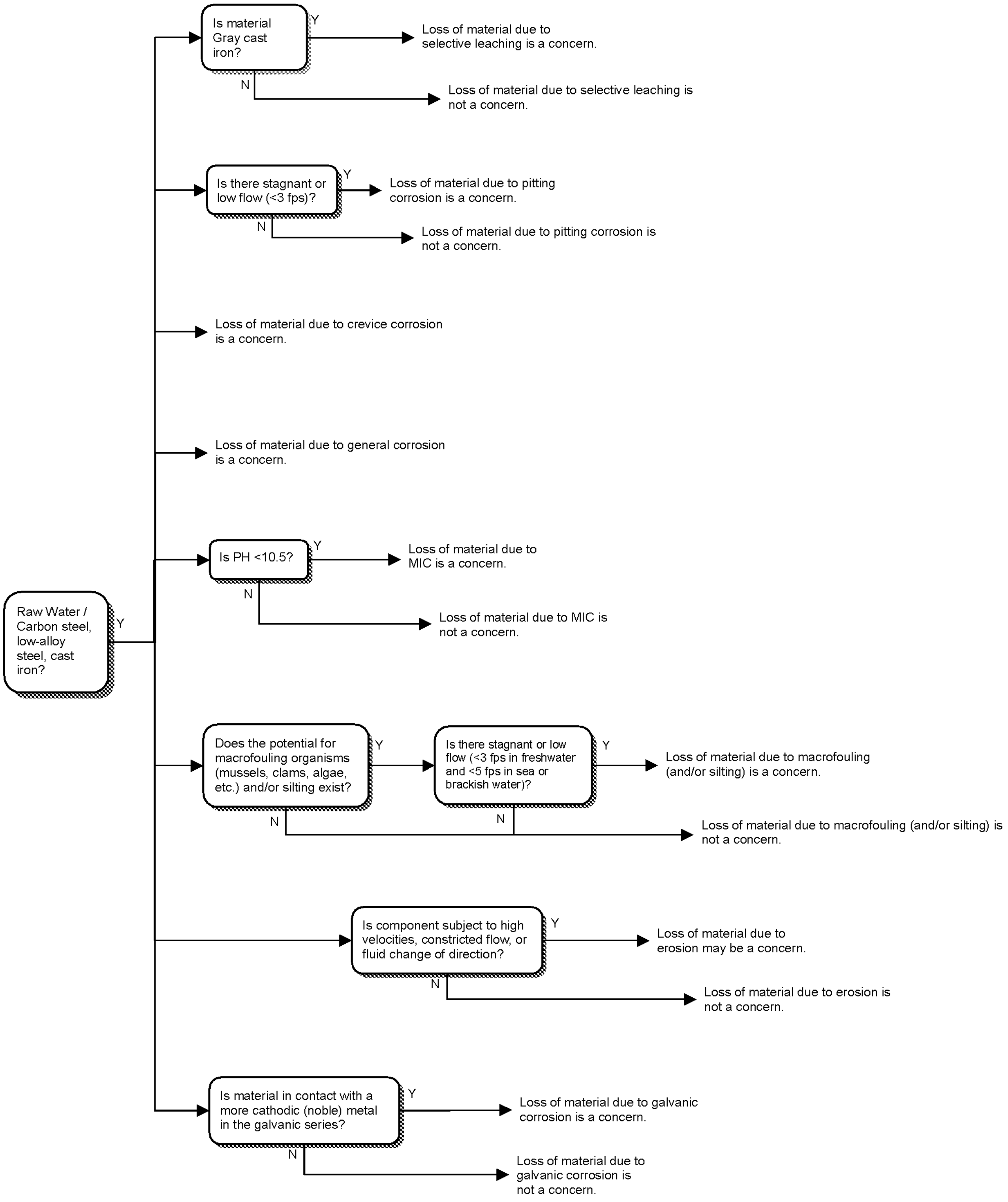
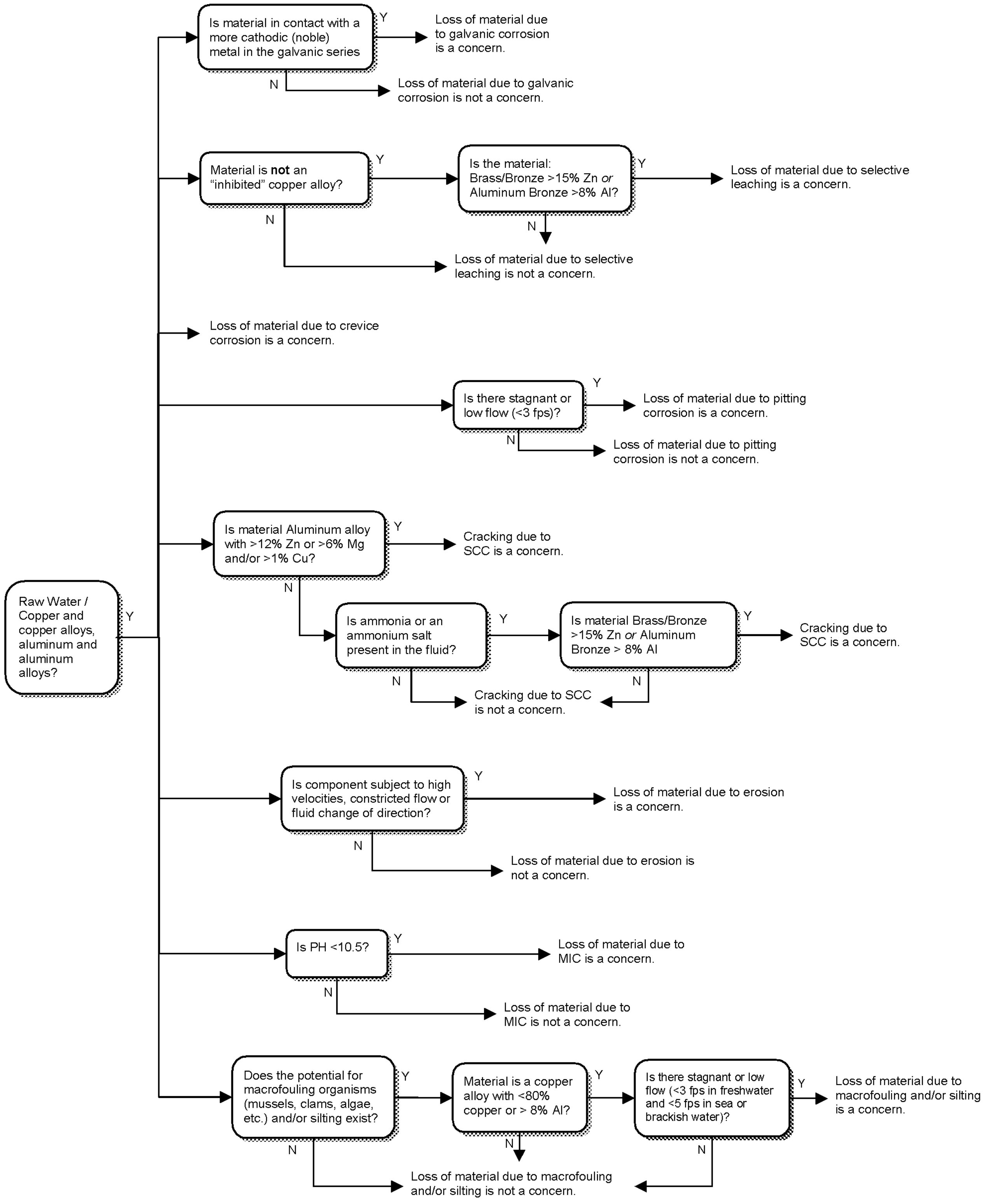


Figure 5 Raw Water / Copper and Copper Alloys, and Aluminum and Aluminum Alloys Tool



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Appendix C - Lubricating Oil and Fuel Oil

The Lubricating 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, 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 diesel fuel 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 various pumps, turbines, etc., and to supplement the Heat Exchanger Tool (Appendix G) for the evaluation of the external (shell-side) surfaces of heat exchanger tubes in a lubricating oil environment.

The materials covered in this tool are stainless steels, carbon and low-alloy steels, aluminum and aluminum alloys, cast iron, copper and various copper alloys (brass, bronze, and copper-nickel), and non-metals such as glass, plastics, and elastomers.

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 lubricating 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.

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1. INTRODUCTION

This aging management tool is intended to cover systems and components containing either lubricating oil 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 make 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/EPIX equipment failure history and NRC generic correspondence data only for the systems and equipment within the scope of license renewal, for reasons other than spatial interaction.

Oil has a variety of applications at nuclear plants, most notably as a lubricant for major rotating equipment. Examples of equipment containing lube oil include emergency and essential diesel generator systems, air compressors, turbines, pumps, 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 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 of construction of the above described components and systems typically include a number of alloys. Carbon steel, low-alloy 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 and copper alloys (brass, bronze, and copper-nickel), aluminum and aluminum alloys, and cast iron. Non-metallic materials such as glass and plastics may also be used in applications such as sight glasses, level gages, tanks, piping, etc. and elastomers may be used in flexible connections/hoses. Consumable non-metallic materials used for gaskets, packing, O-rings, and seals are excluded from aging management, as described in Section 2.2 of the main document (implementation guideline).

The materials and environments covered in the Lubricating Oil and Fuel Oil Tool are discussed in Section 2.0. Aging effects, and the mechanisms that can lead to those effects, that apply to the material and environment combinations are discussed in Section 3.0. The development of the evaluation flow chart and logic and associated summary tables is presented in Section 4.0.

Applicable aging effects include loss of material, cracking, change in material properties (e.g., reduction of fracture toughness, distortion), and loss of mechanical closure integrity. Loss of mechanical closure integrity is not addressed in this tool, but is treated separately in Appendix F

(Bolted Closure Tool). This tool is restricted to internal environment and material combinations. Aging effects for the external surface of components containing oil or fuel oil are addressed in Appendix E. Evaluation of heat exchangers is performed with the tool contained in Appendix G. Likewise, the evaluation of fatigue cracking is addressed in Appendix H and is not covered in this tool.

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 change in material properties (e.g., reduction in fracture toughness, distortion). This oil and fuel oil 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 components that perform their intended function(s) in a passive manner).

As such, 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 environments 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 oil and fuel oil tool includes the more common tubing materials used in coolers, which include stainless steel, aluminum and aluminum alloys, and copper and copper alloys. The underground tanks in 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 (such as water from decontamination activities) 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 and aluminum alloys, (4) cast iron, and (5) copper and 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 the 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-8A) 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. CF-8A is a modification to CF-8, in that a controlled amount of ferrite imparts higher tensile properties.

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 evaluations of this tool applies to all carbon and low-alloy steels.

2.1.3 Aluminum and Aluminum Alloys

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. Aluminum and aluminum alloy products are available in both cast (xxx.x series) and wrought (xxxx series) product forms, with most alloy compositions available in both.

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 are 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].

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 [17].

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). In these iron alloys, the carbon is above the solubility limit of austenite at the eutectic temperature [17]. 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 [6, 21]. 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 [6].

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 [21].

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 [7, 17]. 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. 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% [17]. 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 [17].

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.

2.1.5 Copper and 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 and copper alloys are used to some extent in oil and fuel oil applications and are covered in this tool.

2.1.6 Non-Metals

Glass is an amorphous, inorganic oxide, mostly silica, cooled to a rigid condition without crystallization. Hydrofluoric acid and caustic attack glass, and it shows a slight attack in hot water. Uniform, selective, or localized attack can occur. When hot water attacks glass, it is not dissolved in the usual sense; it hydrolytically decomposes. Resistance to water varies from excellent to poor depending on the glass composition. There are a wide variety of glass compositions with modifiers, fluxes, and stabilizers added to obtain various properties, including corrosion resistance [7]. Fiberglass is often used for underground tanks of petroleum products because of its corrosion resistance. Furthermore, silica is almost insoluble in an aqueous environment except at temperatures in excess of 482°F. Acid attack of soda-lime and borosilicate glass compositions is minimal due to the formation of protective, highly siliceous surface layer, except for hydrofluoric and phosphoric acids (at high temperatures) [22]. No definitive instances of glass failure due to an aging effect have been recorded in industry operating experience searches. Lubricating oil and fuel oil environments do not contain hydrofluoric acids or caustics, nor would glass be exposed to hot water in these environments.

Non-metallic materials such as plastics are also used where temperatures, pressures, and stresses are not limiting and in media (such as aqueous chloride solutions) which cause localized corrosion in metals and alloys. While plastics do not dissolve like metals, they do potentially degrade due to moisture absorption, loss in mechanical properties, hardening, and discoloration. When compared to metals and alloys, plastics are weaker, more resistant to chloride ions, less resistant to oxidizing acids, less resistant to solvents, and have much lower temperature limitations [7]. Polyvinyl chloride (PVC) is a thermoplastic material composed of polymers of vinyl chloride. Manufactured from sodium chloride (NaCl) and natural gas, PVC is relatively unaffected by water, concentrated alkalis, and non-oxidizing acids, oils, and ozone [20]. Polyvinylidene fluoride (PVDF) is a member of the fluorocarbon family of plastics and is a homopolymer of vinylidene fluoride. Extruded as pipe, it is rigid and resists abrasion, as well as being chemically resistant, especially to halogens.

Unlike metals, thermoplastics do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of thermoplastics within a lubrication and fuel oil environment is a design driven criterion. Once the appropriate material is chosen, the material will have no aging effects in the lubrication or fuel oil environment. Aging effects such as UV radiation on the external surface of plastics are addressed in Appendix E.

Elastomers are defined as rubber or polymers that have properties similar to those of rubber. They are used in nuclear plants in various capacities, such as joint sealants, flexible connections/hoses and moisture barriers. For a complete discussion of the aging effects of typical elastomers used in nuclear plants, the user of this tool is referred to EPRI report 1002950, *Aging Effects for Structures and Structural Components (Structural Tools), Revision 1* [18]. Furthermore, certain elastomers such as natural rubbers and ethylene-propylene-diene (EPDM) are not resistant to fuel oil or lubricating oil [23] and only qualified elastomers, that are resistant, are used for oil or fuel oil service.

Therefore, based on industry operating experience review, the assumption of proper design and application of the material, and considering that the oil and fuel oil environments do not typically include contaminants or conditions that would result in the degradation of glass (including fiberglass), thermoplastics, and elastomers, aging of these materials is not a concern in lubrication oil and fuel oil environments.

2.1.7 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. Therefore, this tool does not take credit for any programmatic systems (such as protective coatings) in its determination of applicable aging effect for a given environment so that no such program or activity is implicitly credited for managing the effects of aging in oil and fuel oil environments. The effectiveness of any program or activity that is credited with aging management must be demonstrated as described in Section 4.0 of the implementation guideline and is outside the scope of this tool.

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 coatings.

2.2 Environments

This oil and fuel oil tool includes consideration of various hydrocarbon-based environments, specifically, for the lubricating oil and fuel oil systems and components. A major portion of the environments considered by this tool are associated with the diesel fuel systems and lubricating oil systems for the emergency diesel generators, the diesel driven fire protection pump, and diesel driven high pressure core spray pumps (some BWRs) or other diesel driven equipment in the scope of license renewal. 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 and include the lubricating oil portions of large pumps, turbines, and compressors that are within the scope of license renewal. Some of these diesel generators, pumps, turbines, and compressors use forced lube oil systems, which include oil coolers, pump housings, oil piping, and valve bodies. Others without forced oil lubrication systems may only have an oil housing and oil cooler that are pressure boundary components addressed by this tool.

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.

2.2.1 Lubricating Oil

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, especially in the presence of small amounts of water. Extreme pressure lubricants containing chloride compounds have, in some cases, caused serious corrosion of ferrous steel housings caused by HCl liberation from the additive; this is most severe when the service includes high temperature operation followed by cooling [6]. One of the functions of almost all lubricants is the prevention of corrosion in the lubricating system by water [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.

2.2.2 Fuel Oil

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. Diesel generator fuel oil can be sampled for water prior to being added to the fuel oil storage system, which precludes significant moisture accumulation during transportation. However, this sampling is not credited with preventing water intrusion, so no program or activity is implicitly credited for managing the effects of aging in fuel oil. Furthermore, in the case of storage tanks that are vented to the atmosphere, high humidity or precipitation can lead to some small amount of water intrusion into the fuel oil system. 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.

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, and change in material properties (e.g., reduction of fracture toughness, and distortion). When performing an evaluation of a material and environment combination, 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 the presence of oxygen and moisture, carbon and low-alloy steels and cast iron are susceptible to general corrosion, while stainless steels and aluminum and aluminum alloys 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 steel 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]. However, 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 fuel oil storage tanks or system low points rather than in the flowing portions of systems.

Carbon steel, low-alloy steel, cast iron, and aluminum and aluminum alloys in contact with a more cathodic (noble) material in the galvanic series are susceptible to galvanic corrosion in the presence of an electrolyte, such as in a location where moisture can condense and collect. Copper and copper alloys are in the middle of the galvanic series, with steel, alloy steel, cast iron, and aluminum and its alloys being more anodic (or active) and the stainless steels being more cathodic (or passive). Therefore, copper and copper alloys in contact with a stainless steel are susceptible to galvanic corrosion in the presence of an electrolyte.

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, a bulk fluid oxygen level or the presence of contaminants such as chlorides to sustain the chemical reaction is necessary for the continued corrosion in the crevice [7]. Carbon steel, low-alloy steel, cast iron, stainless steel, aluminum and aluminum alloys, and copper and copper alloys are all susceptible, to some degree, to crevice corrosion [17].

Crevice corrosion of copper and 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 [21]. For most copper metals, the location of the attack is generally outside the crevice, immediately adjacent the crevice region. It can result from the accumulation of rust, permeable scales or deposit of corrosion products at the crevice location. Copper zinc alloys with less than 15% Zn exhibit high resistance to crevice corrosion whereas copper zinc alloys with greater than 15% Zn are susceptible [21]. When the aluminum content of aluminum copper alloys 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.

As discussed 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 for stainless steel, aluminum and aluminum alloys, carbon and low allow steel, cast iron, and high zinc (> 15%) and aluminum bronze (> 8% Al) copper alloys under stagnant conditions where water contamination is present.

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 and aluminum/aluminum alloys than with non-passive materials which include carbon/alloy steels and cast iron. Most 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].

Pitting is an aging mechanism for copper and 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 [21]. 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. While copper alloys are generally resistant to pitting and crevice corrosion, copper zinc alloys with greater than 15% Zn are susceptible. Aluminum bronzes with greater than 8% Al are considered susceptible to pitting under stagnant or low flow conditions.

Corrosion of aluminum and aluminum alloys is localized and usually manifested by random formation of pits. Pitting of aluminum (and aluminum alloys) is most commonly produced by halide ions, of which chloride is the most frequently encountered in service. In the presence of oxygen the metal is readily polarized to its pitting potential. In the absence of dissolved oxygen or other cathodic reactant, aluminum (and aluminum alloys) will not corrode by pitting as it is not polarized to its pitting potential [17].

Oil and fuel oil are not good electrolytes, and water and aggressive species are necessary to propagate this corrosion mechanism. Therefore, pitting corrosion is an aging concern for carbon and low-alloy steel, cast iron, stainless steel, aluminum and aluminum alloys, and high zinc (> 15%) and aluminum bronze (> 8% Al) copper alloys under stagnant conditions where water contamination is present.

3.1.5 Erosion

Erosion is the loss of material due to a flowing fluid. 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 typically not applicable to oil flow at the flow rates and conditions in nuclear plant oil and fuel oil systems and equipment.

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°F; however, it can occur at temperatures up to 210°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 (e.g., 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 materials of interest [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, delivery, and storage. 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.

In summary, MIC is an applicable aging mechanism for carbon and low-alloy steel, cast iron, stainless steel, aluminum and aluminum alloys, and copper and copper alloys in fuel oil systems but is not considered applicable in lubricating oil systems.

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 small amounts of alloying elements such as tin, phosphorus, arsenic, and antimony effectively inhibits dezincification; 1% tin added to brass, for example, significantly reduce the susceptibility of the material [7, 21]. 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. Prolonged contact with waters high in oxygen, carbon dioxide (CO2), or chloride can result in dezincification (a galvanic process) of susceptible materials and is frequently encountered with quiescent or slow moving solutions. Slightly acidic water, low in salt content and at room temperature, is likely to produce uniform attack, but neutral or alkaline water, high in salt content and above room temperature, often produces plug-type attack [17].

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 to resist 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. 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. As such, selective leaching is an applicable mechanism for gray cast iron, brass and bronze (> 15% Zn) copper alloys, and aluminum bronze (> 8% Al) in oil and fuel oil environments in locations where any moisture can condense and/or collect such as the bottom of tanks and heat exchangers and in low points of the system.

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°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 as 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°F. The susceptibility decreases rapidly as the temperature varies above and below 70°F [6, 8]. Alloying with nickel or molybdenum reduces susceptibility [6, 8]. Therefore, the stainless steels 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. It is not expected that equipment within the scope of this tool will experience the corrosive environment necessary for hydrogen damage. Therefore, hydrogen damage is not an applicable aging mechanism for nuclear plant components exposed to fuel oil, unless plant-specific operating experience shows prolonged or recurring use of cathodic protection for fuel oil storage tanks 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.

SCC of Stainless Steel (Wrought and Cast)

SCC and IGA have occurred in stainless steel typically in water systems containing dissolved oxygen, sulfates, fluorides, or chlorides. In general, SCC very rarely occurs in austenitic stainless steels below 140°F [16]. Although SCC has been observed in stagnant, oxygenated borated water systems at lower temperatures than this 140°F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. With a harsh enough environment (significant contamination), SCC can occur in austenitic stainless steel at ambient temperature. However, these conditions are considered event driven, resulting from a breakdown of chemistry controls.

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 the chloride concentration is very high [6].

SCC of Aluminum and Aluminum Alloys

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.

SCC of Copper and 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]. As such, bronzes and copper alloys except brass are not considered susceptible to SCC/IGA for this oil and fuel oil tool.

In summary, although the oil and fuel oil environments 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 and water may accumulate). Therefore, SCC may occur in stainless steel, with temperatures above 140°F, and in certain aluminum and copper alloys in fuel oil systems in locations such as tank and heat exchanger bottoms and piping low points where water and contaminants could collect.

3.2.3 Vibration

Material fatigue resulting from vibration has been observed in the nuclear industry and can result in cracking initiation and growth. Vibration induced fatigue is fast acting and typically detected early in a component's service life and is corrected to prevent recurrence. Corrective actions usually involve modifications to the plant such as the addition of supplemental restraints to a piping system, the replacement of tubing with flexible hoses, or the isolation/elimination of the vibration source when possible. Based upon these considerations, cracking due to vibration fatigue is not considered an applicable aging effect for the period of extended operation of the plant.

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°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 Summary of Potential Aging Effects

Tables 4-1 and 4-2 contain 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.

3.6 Operating History

An operational history review was performed using NPRDS, its successor EPIX, and NRC generic communications that apply to oil and fuel oil systems. Each is reported below.

3.6.1 NPRDS / EPIX Review

The Nuclear Plant Reliability Data System (NPRDS) contains information on plant operating experiences up through 1997. From 1997 through the present, this data is contained in the Equipment Performance and Information Exchange (EPIX) system. 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 and EPIX 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 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 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 and EPIX searches was to identify equipment failures resulting from the effects of aging. Using the above search criteria, 478 entries were selected. As the EPIX search was conducted for Revision 3 of these tools, the above NPRDS search conditions were matched as close as possible for the EPIX queries. Although the EPIX search conditions are not an exact match for the NPRDS conditions, a conservative approach was taken when determining the appropriate search conditions. 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 351 items identified, 285 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 44 entries that represented equipment failures resulting from the effects of aging. Table 3-1 identifies the number of records attributed to the various aging mechanisms and includes a percentage of the total for each category.

Table 3-1 NPRDS / EPIX Search Summary

FAILURE CAUSE	NO. OF ENTRIES	% OF TOTAL
Leaking hoses/fittings/tubing	22	50
Cracking	10	23
Threaded Connections	5	11
Loose bolts/plugs	7	16

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 ten 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 five failures of threaded attachments. 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.

3.6.1.1 Summary of NPRDS / EPIX Search

The NPRDS / EPIX 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 ten incidences of cracking, only one could be directly attributed to corrosion or other pressure boundary material loss aging effects (SCC). It is likely that a number are attributable to vibration.

Although not specifically identified as vibration caused failures, the NPRDS / EPIX 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.

3.6.1.2 Observations and Limitations in Using the NPRDS / EPIX Search Results

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

1. The exact cause of failure is often not clear because of 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.

3.6.2 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. Of these, 10 were considered to be related, either directly or indirectly, to the oil or fuel oil system components. Two were Circulars, 7 were Information Notices, and 1 was a Generic Letter. These entries are discussed briefly below.

Circulars

CR 77-15: Degradation of Fuel Oil Flow to the Emergency Diesel Generator

The purpose of this circular is to inform licensees about degradation of fuel oil flow to the day tank for the emergency diesel generator. Although the fuel oil transfer pump capacity is 13.8 gpm for each of the two redundant pumps, flow to the day tank for the number one diesel generator was only 3 gpm. At full load, engine consumption is 4.5 gpm. Investigation of this occurrence revealed a clogged strainer in a float operated shutoff valve on the day tank inlet. The strainer is an integral part of the float valve assembly and is not shown on the as-built system drawings. Licensees were recommended to perform field verification of the drawing against the as-built system and revise surveillance test procedures as necessary. The circular also provided information relating to the maintenance of fuel oil. The presence of zinc, such as from galvanizing, has a tendency to form soluble soaps in the fuel oil which are deposited on the diesel engine's injection nozzles. A buildup of this deposit will eventually degrade the engine's performance. The presence of copper promotes the formation of gums which degrade the stored fuel oil and tend to clog filters. The presence of water in the fuel oil promotes the growth of fungi or slime that also degrades the fuel and has the potential for clogging filters.

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 is 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 a license renewal credited program (similar to a chemistry program).

3.6.3 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 CR 80-11 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 pump oil collection systems and is not an aging issue.

4. FLOW DIAGRAM/ SUMMARY TABLE DEVELOPMENT

4.1 Assumptions

The assumptions used to develop the evaluation flow chart (and summary tables) 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. "Consumable" items such as 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 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 for fuel oil storage tanks 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.

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 for a given material. Implementation of the tools, in effect, documents the identification of applicable aging mechanisms and the resultant aging effects. 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, which are not in the scope of this tool.

4.3 Tool Descriptions

Tables 4-1 and 4-2 (added in Revision 3) identify applicable aging effects, and corresponding mechanisms, that may require programmatic oversight (management) for the period of extended operation, as well as the applicability criteria for the occurrence and propagation of the mechanisms. These tables summarize the information depicted on the corresponding logic diagrams (Figure 1–Figure 2) and are organized alphabetically by material and then by aging mechanism. The potential aging effects, together with the detailed mechanism discussions in Section 3.0 and assumptions in Section 4.1 of this appendix, provide the basis for the development of the lubricating oil and fuel oil tools described below. The materials and environments covered by these tools are described in Section 2.0.

As discussed in Section 3.2.3, the chosen approach to address the loss of pressure boundary integrity resulting from vibration is to 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.

4.3.1 Lubricating Oil

Section 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 Section 3, the referenced material, and 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.

The remainder of the logic focuses, material by material, on the aging effects that may occur 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 susceptible 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. Aluminum and aluminum alloys are anodic to any other metal in electrolytic contact; whereas copper and copper alloys are anodic when in electrolytic contact with stainless steels but cathodic when in contact with aluminum, carbon and low allow steel, or cast iron. Heat exchangers are particularly susceptible because of the various materials of construction and environments. The tool logic requires some knowledge of the various materials of construction for the evaluation of the likelihood of galvanic corrosion. Although sacrificial anodes, coatings, and separation devices can be used to minimize the likelihood for galvanic corrosion, the tool does not take credit for any programmatic systems in its determination of applicable aging effect for a given environment.

The logic also addresses selective leaching. Only gray cast iron and uninhibited copper alloys with high zinc and aluminum contents in the presence of pooled water are affected.

4.3.2 Fuel Oil

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]. However, the tool does not take credit for any programmatic systems in its determination of applicable aging effects for a given environment.

Cathodic protection has been known to result in hydrogen damage to carbon and low-alloy steel (conservatively also applied to cast iron) 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.

The top tier 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 tier addresses many different materials and focuses on the various corrosion mechanisms that may occur for those materials affected by these mechanisms.

In a wetted environment, with oxygen > 100 ppb and Temperature > 140°F, all stainless steels within the scope of this tool are considered to be susceptible to stress corrosion cracking (SCC). Stainless steels are also susceptible to crevice and pitting corrosion in wetted environments regardless of temperature and O_2 content.

Galvanic corrosion is only a concern where materials are in contact in the presence of an electrolyte (e.g., pooled water) and are distant from each other in the galvanic series. Only the more anodic material is affected (e.g., carbon steel and copper alloys are 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.

Pure aluminum is not susceptible to stress-corrosion cracking. 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 brasses containing greater than 15% zinc (including admiralty and Muntz) and aluminum bronzes with greater than 8% aluminum are susceptible to SCC in wetted locations with O_2 > 100 ppb. Pitting and/or crevice corrosion is also a concern for all copper alloy materials covered by this tool.

Selective leaching in a wetted environment can occur, particularly when oxygen, carbon dioxide, or chlorides are present. The logic tree addresses this issue identifying uninhibited copper alloys with high zinc and aluminum contents and gray cast iron as the only materials susceptible to this loss of material effect.

In a wetted environment, general corrosion of carbon and low-alloy steel as well as cast iron is a concern, as is crevice and/or pitting corrosion of these materials.

4.4 GALL Comparison

The information in Chapters IV, V, VII, and VIII of Volume 2 of NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results," identifies material, environment(s), aging effects (and associated mechanisms) typically requiring management for license renewal applicants, and the suggested aging management program (AMP) for various mechanical components. GALL Chapters V, VII, and VIII tables all include items for oil environments addressed by this tool. GALL Chapter IV (Reactor Vessel, Internals, and Reactor Coolant System) is focused on Class 1 components that are not addressed by this tool and does not include oil environments. The identification and evaluation of aging management programs (AMPs) is outside the scope of this tool and should be addressed on a plant-specific basis, as described in Section 4.0 of the main document.

While component identification is also outside the scope of this tool, the materials for the pertinent items in GALL Chapters V, VII, and VIII are consistent with the materials addressed by this tool, which are described in Section 2.1. Carbon or low-alloy steel is referred to as "steel" in the GALL items for environments addressed by this tool. Cast iron is included with "steel" in the GALL items for environments addressed by this tool. Copper and copper alloys are referred to as "copper alloy" and aluminum and aluminum alloys are referred to as "aluminum" in the GALL items for environments addressed by this tool. The GALL items for environments addressed by this tool also include glass and stainless steel.

The following GALL Chapters V, VII, and VIII environments (fuel oil and lubricating oil) are bounded by the environments addressed in these oil and fuel oil tools, which are described in Section 2.2.

The GALL items addressing glass in lubricating oil (V.F-7, VII.J-10, and VIII.I-6) and fuel oil (VII.J-9) concur with the conclusions of Section 2.1.6 of this tool with respect to degradation of glass exposed to oil not being a concern.

The GALL does not evaluate mechanisms separately, as is done in Section 3.0 of this tool. Additionally, the aging mechanisms identified in GALL Chapters V, VII, and VIII are grouped without clear indication as to the basis for mechanisms (e.g., MIC and/or fouling) that are indicated as applicable to certain components but not to others. The aging effect cited in GALL Chapters V, VII, and VIII for metals in the lubricating oil and fuel oil environments includes loss of material, with the following groupings of mechanisms depending on material susceptibility:

- General, pitting, and crevice corrosion
- General, pitting, crevice, and microbiologically influenced corrosion, and fouling
- Pitting, and crevice corrosion
- Pitting, crevice, and microbiologically influenced corrosion

Consistent with the discussions in Section 3.0 of this tool, the aging effect identified in the GALL as requiring management (loss of material) for metals in fuel oil and lubricating oil environments is associated with water pooling in the oil. The GALL does not identify cracking due to SCC/IGA or loss of material due to galvanic corrosion or selective leaching in lubricating oil or fuel oil environments, whereas they are evaluated in this tool, in Sections 3.2.2, 3.1.2, and 3.1.8, respectively. The GALL Chapters V, VII, and VIII items that identify aging effects for external surfaces, closure bolting, and heat exchangers are addressed separately in Appendix E, Appendix F, and Appendix G, respectively. Likewise, GALL items for fatigue are evaluated separately in Appendix H and are not addressed in this tool.

Table 4-1 Aging Effects Summary - Lubricating Oil

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Aluminum and Aluminum Alloys	Loss of Material / Crevice and/or Pitting Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation	None	No	Sections 2.1.3, 3.1.3 Assumptions 4.1.1, 4.1.3 GALL Chapters V, VII, and VIII do not include items that address aluminum (or aluminum alloys) in lubrication oil, only for fuel oil (See Table 4-2).
	Loss of Material / Galvanic Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation *and* 3. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.3, 3.1.2 GALL Chapters V, VII, and VIII do not include items that cite galvanic corrosion in lubricating oil, but cite galvanic corrosion for copper alloy only in treated water (or closed cooling water) environments.
Carbon Steel and Low-Alloy Steel *and* Cast Iron	Loss of Material / Crevice and/or Pitting Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation	V.A-25, V.D1-28, V.D2-30 VII.C1-17, VII.C2-13, VII.E1-19, VII.E4-16, VII.F1-19, VII.F2-17, VII.F3-19, VII.F4-15, VII.G-22, VII.G-26,	Yes	Sections 2.1.2, 2.1.4, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3
	Loss of Material / General Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation			Sections 2.1.2, 2.1.4, 3.1.1 Specified GALL items list general, pitting and crevice corrosion of steel exposed to lubricating oil. GALL items for "steel" include both carbon steel, low-alloy steel, and cast iron.

Table 4-1 Aging Effects Summary - Lubricating Oil					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Carbon Steel and Low-Alloy Steel *and* Cast Iron (Cont'd)			VII.G-27, VII.H2-20 VIII.A-14, VIII.D1-6, VIII.D2-5, VIII.E-32, VIII.G-35		
	Loss of Material / Galvanic Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation *and* 3. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.2, 2.1.4, 3.1.2 GALL Chapters V, VII, and VIII do not include items that cite galvanic corrosion in lubricating oil, only in treated water environments.
Cast Iron *and* Copper and Copper Alloys	Loss of Material / Selective Leaching	1. Presence of water contamination *and* 2. Potential for water pooling / separation *and* 3. Material is gray cast iron *or* Brass/bronze >15% Zn *or* Aluminum bronze > 8% Al *and* 4. Copper alloy is uninhibited Note: Small amounts of alloying elements such as tin, phosphorus, arsenic and antimony (e.g., 1% tin to brass) effectively inhibit dezincification. Aluminum bronzes are inhibited by adding 0.02 to 0.10% As.	None	No	Sections 2.1.4, 2.1.5, 3.1.8 Assumption 4.1.1 GALL Chapters V, VII, and VIII do not list selective leaching as an applicable aging effect in lubricating oil environments.

Table 4-1 Aging Effects Summary - Lubricating Oil					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys	Loss of Material / Crevice and/or Pitting Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation *and* 3. Material is Brass/Bronze > 15% Zn *or* Aluminum Bronze > 8% Al	V.A-21, V.D1-18, V.D2-22 VII.C1-8, VII.C2-5, VII.E1-12, VII.E4-6, VII.G-11, VII.H2-10 VIII.A-3, VIII.D1-2, VIII.D2-2, VIII.E-17, VIII.G-19	Yes	Sections 2.1.5, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3 Specified GALL items list pitting and crevice corrosion as applicable aging mechanisms for copper alloy in lubricating oil, but do not include applicability criteria regarding water pooling or zinc/aluminum content. GALL items do not distinguish between copper and copper alloys, or between copper alloys with > 15% Zn or > 8% Al and copper alloy, with respect to crevice and pitting corrosion.
	Loss of Material / Galvanic Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation *and* 3. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.5, 3.1.2 GALL Chapters V, VII, and VIII do not include items that cite galvanic corrosion in lubricating oil, only in treated water environments.

Table 4-1 Aging Effects Summary - Lubricating Oil					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Stainless Steel	Loss of Material / Crevice and/or Pitting Corrosion	1. Presence of water contamination *and* 2. Potential for water pooling / separation	V.D1-24 VII.C1-14, VII.C2-12, VII.E1-15, VII.E4-12, VII.G-18, VII.H2-17 VIII.A-9, VIII.D1-3, VIII.D2-3, VIII.E-26, VIII.G-29	No	Sections 2.1.1, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3 Specified GALL items list pitting, crevice, and microbiologically influenced corrosion (MIC) as applicable aging mechanisms for stainless steel in lubricating oil. With respect to crevice and pitting corrosion the GALL and this tool are consistent. However, MIC is not identified in GALL as an aging mechanism requiring management for other materials in lubricating oil. Also, MIC is not cited as an aging mechanism requiring management for stainless steel in lubricating oil for GALL item V.D1-24. The GALL does not include the reason/basis that MIC requires management in lubricating oil environments for stainless steel in certain systems, but does not for stainless steel in other systems or for other materials, regardless of the system. Furthermore, as described in Section 3.1.6, the likelihood of MIC causing extensive damage in lube oil systems is minimal and loss of material due to MIC is not an applicable aging effect.

Table 4-2 Aging Effects Summary - Fuel Oil					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Aluminum and Aluminum Alloys	Loss of Material / Crevice and/or Pitting Corrosion	1. Potential for water pooling / separation	VII.H1-1, VII.H2-7	Yes	Sections 2.1.3, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3 Specified GALL items cite pitting, crevice, and microbiologically influenced corrosion as applicable aging mechanisms for aluminum in fuel oil.
	Loss of Material / Galvanic Corrosion	1. Potential for water pooling / separation *and* 2. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.3, 3.1.2 GALL Chapters V, VII, and VIII do not identify galvanic corrosion as an applicable aging mechanism in fuel oil.
	Loss of Material / MIC	1. Always	VII.H1-1, VII.H2-7	Yes	Sections 2.1.3, 3.1.6 Assumptions 4.1.5, 4.1.6 Specified GALL items cite pitting, crevice, and microbiologically influenced corrosion as applicable aging mechanisms for aluminum in fuel oil.
	Cracking / SCC/IGA	1. Potential for water pooling / separation *and* 2. Material is aluminum alloy > 12% Zn or > 6% Mg	None	No	Sections 2.1.3, 3.2.2 Assumptions 4.1.1, 4.1.4 GALL Chapters V, VII, and VIII do not address SCC/IGA as an applicable aging effect in oil environments.

Table 4-2 Aging Effects Summary - Fuel Oil

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Carbon and Low-Alloy Steel *and* Cast Iron	Loss of Material / Crevice and/or Pitting Corrosion	1. Potential for water pooling / separation	VII.G-21 VII.H1-10, VII.H2-24	Yes	Sections 2.1.2, 2.1.4, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3
	Loss of Material / General Corrosion	1. Potential for water pooling / separation			Sections 2.1.2, 2.1.4, 3.1.1 Specified GALL items cite general, pitting, and crevice corrosion of steel. Items VII.H1-10 and VII.H2-24 also list MIC and fouling as applicable aging mechanisms (see below).
	Loss of Material / Galvanic Corrosion	1. Potential for water pooling / separation *and* 2. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.2, 2.1.4, 3.1.2 GALL Chapters V, VII, and VIII include items for galvanic corrosion in treated water only, and do not identify it as an aging mechanism requiring management in fuel oil.
	Loss of Material / MIC	1. Always	VII.H1-10, VII.H2-24	No	Sections 2.1.2, 2.1.4, 3.1.6 Assumptions 4.1.5, 4.1.6 GALL items VII.H1-10 and VII.H2-24 cite MIC and fouling as aging mechanisms that require management in fuel oil, along with general, crevice, and pitting corrosion. However, GALL item VII.G-19 (see crevice/pitting discussion above) does not list microbiologically influenced corrosion or fouling as an aging mechanism that requires management in fuel oil, which implies that MIC and fouling may occur in certain systems but not in others.

Table 4-2 Aging Effects Summary - Fuel Oil

Material	Aging Effect / Mechanism	Mechanism Applicability Criteria	NUREG-1801 (GALL) Item No.	Tool vs GALL Match	Relevant Sections, Assumptions, and Discussion
Carbon and Low-Alloy Steel *and* Cast Iron (Cont'd)	Cracking / Hydrogen Damage (Embrittlement)	1. Material is carbon or low-alloy steel (for fuel oil storage tanks). *and* 2. Impressed current cathodic protection system is utilized *and* 3. Plant-specific operating experience shows prolonged or recurring use at improper voltage settings. Note: Hydrogen embrittlement may also be evidenced by a reduction of fracture toughness.	None	No	Sections 2.1.2, 2.1.4, 3.2.1 Assumptions 4.1.7 GALL Chapters V, VII, and VIII do not identify cracking or reduction of fracture toughness for metals or in fuel oil environments.
Cast Iron *and* Copper and Copper Alloys	Loss of Material / Selective Leaching	1. Potential for water pooling / separation *and* 2. Material is gray cast iron *or* Brass/bronze >15% Zn *or* Aluminum bronze > 8% Al *and* 3. Copper alloy is not inhibited Note: Small amounts of alloying elements such as tin, phosphorus, arsenic and antimony (e.g., 1% tin to brass) effectively inhibit dezincification. Aluminum bronzes are inhibited by adding 0.02 to 0.10% As.	None	No	Sections 2.1.4, 2.1.5, 3.1.8 Assumption 4.1.1 GALL Chapters V, VII, and VIII do not include items for selective leaching in oil environments.

Table 4-2 Aging Effects Summary - Fuel Oil					
Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Copper and Copper Alloys	Loss of Material / Crevice and/or Pitting Corrosion	1. Potential for water pooling / separation *and* 2. Material is Brass/Bronze > 15% Zn *or* Aluminum Bronze > 8% Al	VII.G-10, VII.H1-3, VII.H2-9	No	Sections 2.1.5, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3 Specified GALL items cite pitting, crevice, and microbiologically influenced corrosion as applicable aging mechanisms for copper alloys in fuel oil. However, these GALL items do not distinguish between copper alloy and copper alloy with > 15% Zn or > 8% Al.
	Loss of Material / Galvanic Corrosion	1. Potential for water pooling / separation *and* 2. Contact with a more cathodic (noble) metal in the galvanic series	None	No	Sections 2.1.5, 3.1.2 GALL Chapters V, VII, and VIII do not include galvanic corrosion as an aging mechanism requiring management in fuel oil.
	Loss of Material / MIC	1. Always	VII.G-10, VII.H1-3, VII.H2-9	Yes	Sections 2.1.5, 3.1.6 Assumptions 4.1.5, 4.1.6 See above discussion for crevice and/or pitting corrosion.
	Cracking / SCC/IGA	2. Potential for water pooling / separation *and* 3. O_2 > 100 ppb *and* 4. Material is Brass > 15% Zn or Aluminum bronze > 8% Al	None	No	Sections 2.1.5, 3.2.2 Assumptions 4.1.1, 4.1.4 GALL Chapters V, VII, and VIII do not include items for cracking due to SCC/IGA as an aging effect that requires management in oil environments.

Table 4-2 Aging Effects Summary - Fuel Oil

Material	**Aging Effect / Mechanism**	**Mechanism Applicability Criteria**	**NUREG-1801 (GALL) Item No.**	**Tool vs GALL Match**	**Relevant Sections, Assumptions, and Discussion**
Stainless Steel	Loss of Material / Crevice and/or Pitting Corrosion	1. Potential for water pooling / separation	VII.G-17, VII.H1-6, VII.H2-16	Yes	Sections 2.1.1, 3.1.3, 3.1.4 Assumptions 4.1.1, 4.1.3
	Loss of Material / MIC	1. Always			Sections 2.1.1, 3.1.6 Assumptions 4.1.5, 4.1.6 Specified GALL items cite loss of material due to pitting, crevice, and microbiologically influenced corrosion as aging effects that require management for stainless steel in fuel oil.
	Cracking / SCC/IGA	1. Potential for water pooling / separation *and* 2. $O_2 > 100$ ppb *and* 3. Temperature > 140°F	None	No	Sections 2.1.1, 3.2.2 Assumptions 4.1.1, 4.1.4 GALL Chapters V, VII, and VIII do not include items that identify cracking due to SCC/IGA as aging effects that require management in oil environments.

Figure 1 Lubricating Oil Tool

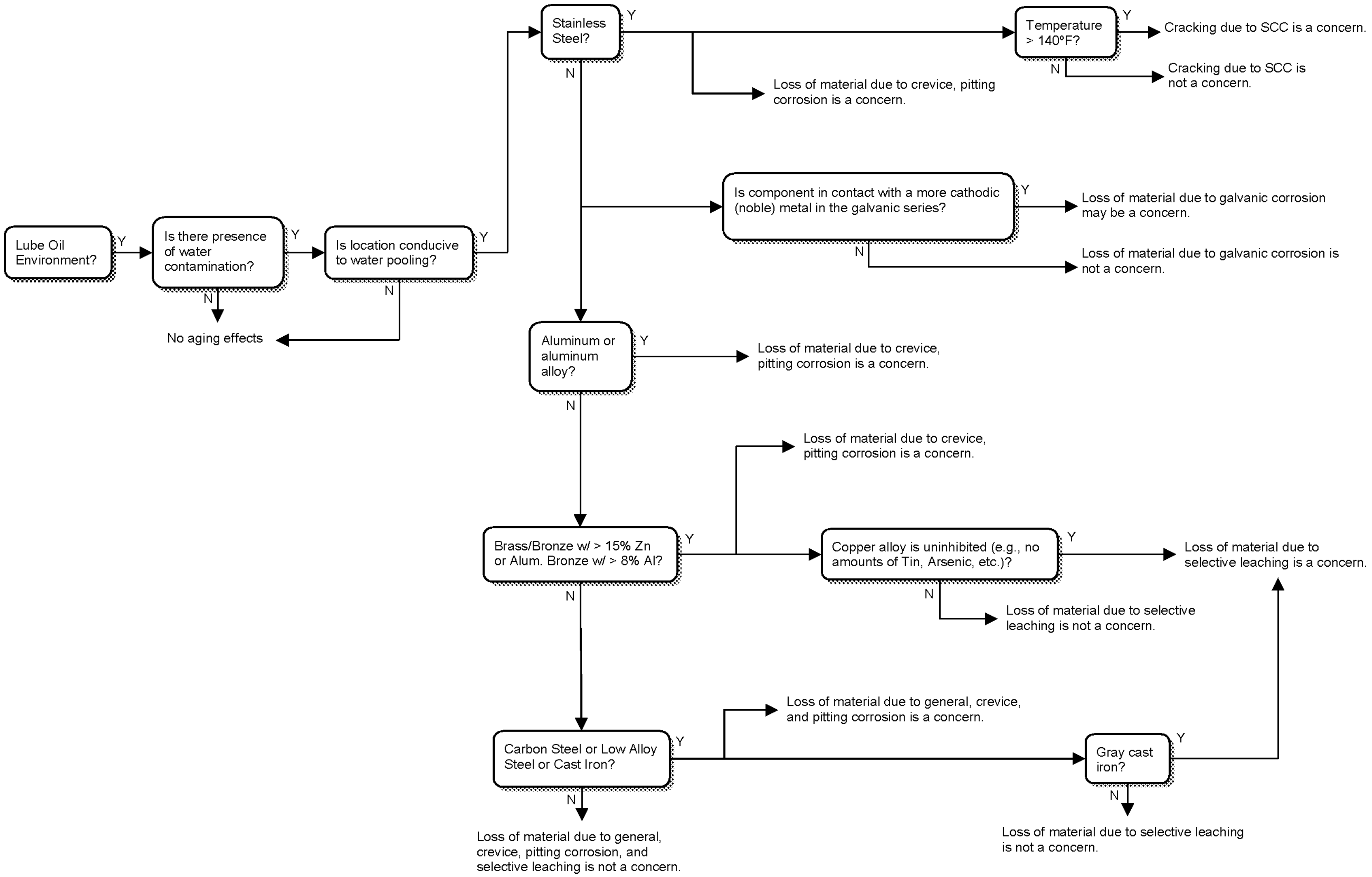
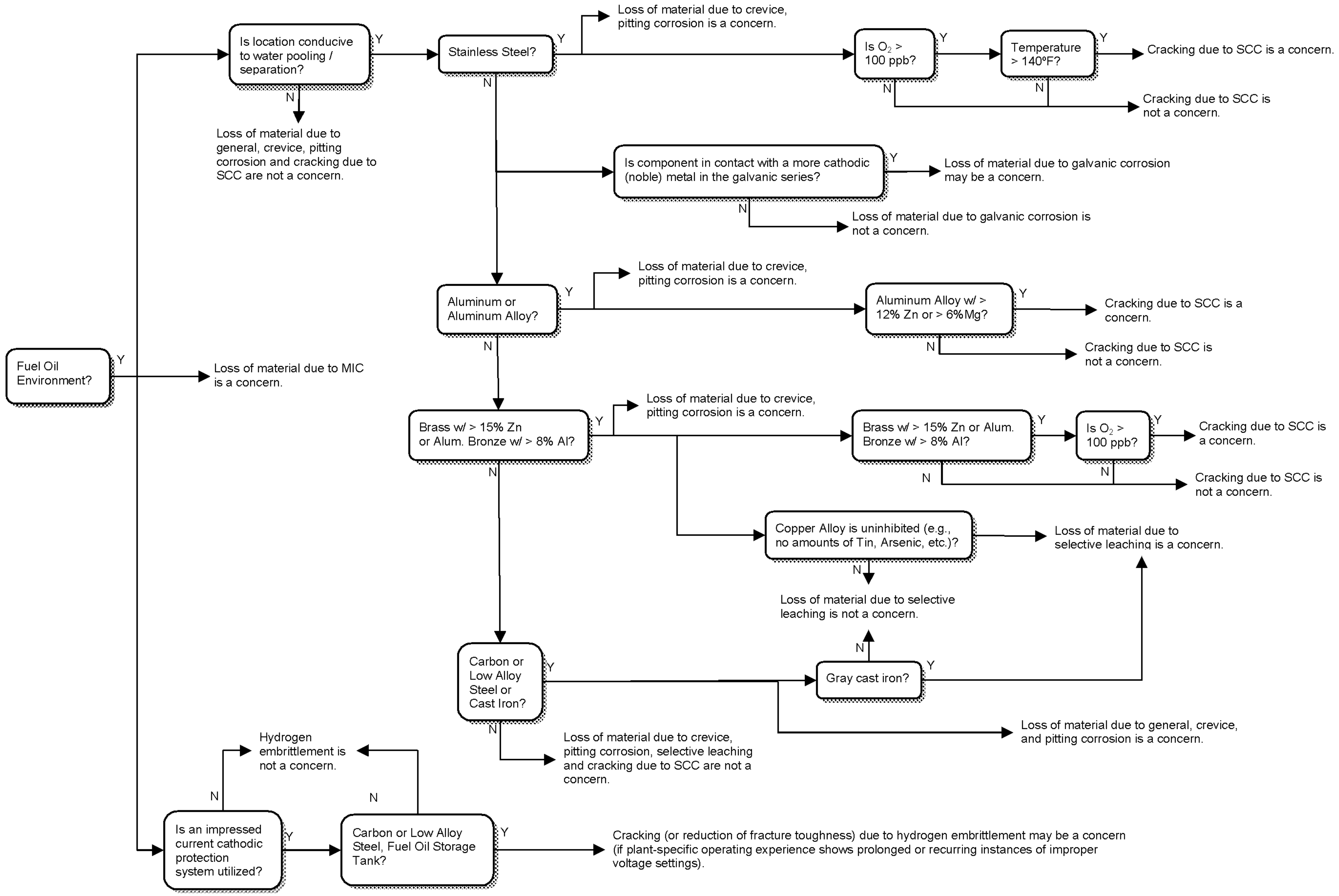


Figure 2 Fuel Oil Tool



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Appendix D - Air/Gas

The Air/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, helium, halon, and refrigerants. This tool is designed for use with any component that has 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, low-alloy, and stainless steel, nickel-base alloys, galvanized steel, copper and copper alloys (brass, bronze, and copper-nickel), aluminum and aluminum alloys, cast iron, and non-metals such as glass, plastics, and elastomers.

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 logics 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 Air/Gas 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, refrigerants, halon, 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 the 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 identified.

The various materials used in passive parts of the above described components and systems typically include a number of metals and alloys. Carbon steel, low-alloy steel, and stainless steel are typically used for piping, tanks, pressure vessels, and accumulators, although nickel-base alloys may also have limited use. Portions of air and gas system piping, tubing, and fittings may also include brass, bronze, or other copper and copper alloys, aluminum and aluminum alloys, and cast iron. Ductwork for air supply systems may be constructed of galvanized steel, may include non-metallic material, and can include a variety of the above metals.

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.

An integral part of the development of this tool is consideration of industry failure data contained in the NPRDS (or EPIX) 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.

The materials and environments covered in the Air/Gas Tool are discussed in Section 2.0. Aging effects, and the mechanisms that can lead to those effects, that apply to the material and environment combinations are discussed in Section 3.0. The development of the evaluation flow chart, logic, and associated summary table is presented in Section 4.0.

Applicable aging effects include loss of material, cracking, change in material properties (e.g., reduction of fracture toughness, distortion), and loss of mechanical closure integrity. Loss of mechanical closure integrity is not addressed in the Air/Gas Tool, but is treated separately in Appendix F. This tool is restricted to internal environment and material combinations. Aging effects for the external surface of materials in various environments, such as humid air, are addressed in Appendix E. Evaluation of heat exchangers is performed with the tool contained in Appendix G. Likewise, the evaluation of fatigue cracking is addressed in Appendix H and is not covered in this Air/Gas Tool.

2. MATERIALS AND ENVIRONMENTS

The Air/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 space, and makeup tank hydrogen blanket) in addition to being in contact with fluids discussed in Appendices A-C.

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 and aluminum alloys, (5) cast iron, (6) copper and copper alloys (brass, bronze, and copper-nickel), (7) galvanized steel, and (8) non-metals such as glass, plastics, and elastomers.

2.1.1 Stainless Steels

The stainless steels discussed in this 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-8A) 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. CF-8A is a modification to CF-8 in that a controlled amount of ferrite imparts higher tensile properties.

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 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 2. The cladding is assumed to be equivalent to the wrought austenitic stainless steels with respect to the discussions of loss of material, cracking, and reduction of fracture toughness in Section 3.0 of this appendix.

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.

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 metals 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 and Aluminum Alloys

Aluminum and its alloys have 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 and aluminum alloys may also have limited use as ductwork in air supply systems. Aluminum and aluminum alloys can also be used in the housings of fans and heaters.

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 are 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 for 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 be and are added to cast iron alloys to promote an array of hardness, corrosion resistance, heat resistance and abrasion resistance properties [1].

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). 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 [5]. 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.

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, 5]. 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 [5]. 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 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.

2.1.6 Copper and 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 [Reference 1, p. 4-26]. 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 [Reference 1, pp. 4-26, 4-94].

2.1.8 Non-Metals

Glass is an amorphous, inorganic oxide, mostly silica, cooled to a rigid condition without crystallization. Hydrofluoric acid and caustic attack glass, and it shows a slight attack in hot water. Uniform, selective, or localized attack can occur. When hot water attacks glass, it is not dissolved in the usual sense; it hydrolytically decomposes. Resistance to water varies from excellent to poor depending on the glass composition. There are a wide variety of glass compositions with modifiers, fluxes, and stabilizers added to obtain various properties, including corrosion resistance [5]. No definitive instances of glass failure due to an aging effect have been recorded in industry operating experience searches. Gas environments do not contain hydrofluoric acids or caustics, nor would glass be exposed to hot water in these environments.

Non-metallic materials such as plastics are also used where temperatures, pressures, and stresses are not limiting and in media (such as aqueous chloride solutions) which cause localized corrosion in metals and alloys. While plastics do not dissolve like metals, they do potentially degrade due to moisture absorption, loss in mechanical properties, hardening, and discoloration. When compared to metals and alloys, plastics are weaker, more resistant to chloride ions, less resistant to oxidizing acids, less resistant to solvents, and have much lower temperature limitations [5]. Polyvinyl chloride (PVC) is a thermoplastic material composed of polymers of vinyl chloride. Manufactured from sodium chloride (NaCl) and natural gas, PVC is relatively unaffected by water, concentrated alkalis, and non-oxidizing acids, oils, and ozone [22]. Polyvinylidene fluoride (PVDF) is a member of the fluorocarbon family of plastics and is a homopolymer of vinylidene fluoride. Extruded as pipe, it is rigid and resists abrasion, as well as being chemically resistant, especially to halogens. It is impervious to deionized water which can cause organic and inorganic particulates to leach from

PVC. PVDF is highly corrosion resistant and can withstand years of in-ground exposure to moisture and chemicals [22].

Unlike metals, thermoplastics do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of thermoplastics within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects.

Elastomers are defined as rubber or polymer that has properties similar to those of rubber. They are used in nuclear plants in various capacities, such as joint sealants (e.g., for duct and fans in HVAC systems), moisture barriers, and flexible connections. The outstanding characteristic of rubber and elastomers is resilience or low modulus of elasticity. Flexibility accounts for most applications. However, chemical and abrasion resistance, and good insulating qualities, result in many corrosion applications. Generally speaking, the natural rubbers have better mechanical properties than the synthetic or artificial rubbers (e.g., neoprene), but the synthetics have better corrosion resistance [5]. For example, natural rubbers are degraded by ozone and sunlight, whereas synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation) [5 and 19].

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 gases, including water vapor. The internal surfaces of a majority of components are at some time exposed to air either continuously (as in a forced air system) or intermittently (as during maintenance). 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 depending on 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 it 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]. In BWRs, the primary containment atmosphere is typically inert nitrogen to minimize the risk of a fire but may include, depending on plant-specific operating experience, some amount of dissolved oxygen or become saturated during normal plant operations and particularly during outages, when the primary containment is open to air.

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 may contain a hydrogen blanket to scavenge oxygen from the makeup fluid. Hydrogen is injected into the reactor primary fluid in many 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, and 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 tool 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 Refrigerants

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 400°F 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% 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]. Plant operating experience should be reviewed to assure that moisture and/or aggressive species intrusion conditions do not exist at the user's site.

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

2.2.7 Halon

Halon is used as a fire extinguishing agent in built-in systems and handheld portable extinguishers. Halon, a halogenated hydrocarbon, is a liquefied, compressed gas that stops the spread of fire by chemically disrupting combustion. Halon 1211 (a liquid streaming agent that gasifies under normal atmospheric conditions) and Halon 1301 (a gaseous flooding agent) leave no residue and are remarkably safe for human exposure. Halon is most effective for flammable liquids and electrical fires and is electrically non-conductive. Halon is one of the most commonly used fire suppressants, but has sufficient ozone depleting potential that its production and use should be restricted. Non-ozone depleting alternatives to Halon could be sufficiently corrosive to cause corrosion failure of fire suppressant storage and distribution systems. If replacement gases are corrosive, then the systems in which they are used must be screened for potential aging effects.

2.2.8 Fission Gases

Systems at nuclear plants can be subjected to a variety of short and long lived gaseous 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, and change in material properties (e.g., reduction of fracture toughness, distortion) for materials exposed to various gas environments. 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 Sections 2.1 and 2.2 of this tool. For the most part gases 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 and aluminum alloys, copper and copper alloys, and galvanized steel are resistant to general corrosion [6].

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 [Reference 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 general (uniform) 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. The Generic Aging Lessons

Learned (GALL) Report [18] supports this conclusion so long as plant-specific operating experience does not indicate that moisture and contaminants have been introduced into normally dry portions of systems. Operating experience exists (see Section 3.7.1) showing that failures of dryers and filters have resulted in the introduction of sludge, moisture, and other contaminants into dry portions of gas bearing systems. Plant-specific operating experience should be reviewed to assure that the user of this tool has not also had these failures.

With respect to air sources for plant systems, (e.g., ventilation and intake systems), atmospheres can be classified as industrial, marine, or rural for the purposes of this tool. Corrosion is primarily due to moisture and oxygen but is accentuated by contaminants 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]. While this tool does not evaluate general corrosion rates, users are encouraged to research general corrosion rates for their local area. This may involve locating corrosion data from nearby industrial sites and/or reviewing data presented in EPRI TR-103840, *BWR Containments License Renewal Industry Report, Revision 1*, July 1994. Upon review of this data, bounding corrosion rates can be determined and utilized in evaluations of the impact of these rates on the intended functions of components (for example, the effect of combined exterior and interior corrosion rates on a pressure boundary wall thickness for the period of extended operation).

Galvanized steel is carbon steel protected by coating the surface with zinc. Zinc is used because of its corrosion resistance in atmospheric conditions and because it provides 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 [9]. In the pH range between 6 and 12, zinc undergoes negligible corrosion under most environmental conditions. When exposed to water, the corrosion resistance of zinc is maintained only in this pH range. Outside this pH range, the increased corrosion rate significantly reduces the usefulness of zinc as a protective coating. Temperature also affects the corrosion rate of galvanized steel. Several studies indicate that between 140°F and 200°F, the corrosion products are significantly more conductive than those formed above or below these temperatures. The corrosion products at 185°F were noted to be about 1,000 times more conductive (a measure of impurities) than those at 75°F (in distilled water) [9]. Therefore, the potential for degradation of the zinc coating can occur on wetted surfaces in this temperature range. For example, corrosion may occur at points or in an HVAC system where moisture can condense and/or collect in the above temperature range or outside the above pH range.

In summary, carbon and low-alloy steels and cast iron are susceptible to general corrosion in saturated/moist air environments, and in nitrogen or other gas environments where the gas becomes saturated and/or includes some amount of dissolved oxygen. General corrosion (uniform attack) is not a concern in dried air, nitrogen, CO_2, hydrogen, halon, or fluorocarbon (refrigerant) environments. Corrosion that may occur at the interface of a blanket/cover gas and a liquid is more likely to be localized attack rather than a uniform loss of material and is discussed in the appropriate section below. Galvanized steel is susceptible to general corrosion in wetted locations in the temperature range of 140°F to 200°F or outside the pH range of 6 to 12.

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].

Carbon steel, low-alloy steel, cast iron, and aluminum and aluminum alloys in contact with a more cathodic (noble) material in the galvanic series are susceptible to galvanic corrosion in the presence of an electrolyte such as a water-saturated gas or in a location where moisture can condense and collect (e.g., air storage tank). Copper and copper alloys are in the middle of the galvanic series with steel, alloy steel, cast iron, and aluminum and aluminum alloys being more anodic (or active) and with the stainless steels and nickel-base alloys being slightly more cathodic (or passive). Therefore, copper and copper alloys in contact with a stainless steel or nickel-base alloy may be susceptible to galvanic corrosion in the presence of an electrolyte.

Furthermore, an aggressive species, such as saltwater (salt air) in marine (seashore) areas or sulfur dioxide in industrial areas, may increase the electrolytic potential of the normal atmosphere (humidity). As such, galvanic corrosion may be a potential aging mechanism for dissimilar metal connections involving susceptible materials when ambient outdoor air is the source. Examples of potential areas are in air intake or HVAC systems for plants whose operating experience has shown exposure to aggressive species such as salt air in seashore areas or sulfur dioxide in industrial areas.

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 aggressive environments such as the presence of S, Cl, or I. An oxygen content in the fluid is required to initiate crevice corrosion [9]. 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 or the presence of contaminants to sustain the chemical reaction is necessary for the continued corrosion in the crevice [5]. 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, an aggressive chemical species (e.g., halides, sulfates) and moisture can provide an environment severe enough to propagate 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. Stainless steels and aluminum alloys are notoriously susceptible to attack [7]. Crevice corrosion of copper and copper-based 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. For most copper metals, the location of the attack is generally outside the crevice, immediately adjacent the crevice region. Copper-zinc alloys with less than 15% zinc content exhibit high resistance to crevice corrosion whereas copper-zinc alloys with greater than 15% zinc are susceptible [1]. The level of oxygen for any specific application will vary with any gas environment other than air, and 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 autocatalytic or self-stimulating and self-propagating after it is initiated [7].

Another form of pitting corrosion can occur at a gas to liquid interface. This form of corrosion is commonly called water-line attack [1]. Typically, a differential aeration cell is developed at the liquid surface leading to the localized attack just below the water line. All materials susceptible to pitting are susceptible to this type of attack.

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]. Copper-zinc alloys with less than 15% zinc content exhibit high resistance to pitting corrosion whereas copper-zinc alloys with greater than 15% zinc are susceptible. Aluminum bronze alloys with greater than 8% aluminum are also highly susceptible to pitting [1].

3.1.5 Erosion

Erosion is the loss of material due to a flowing fluid. 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 120°F. Microbiological organisms disrupt the 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 (e.g., due to contact with contaminated soils) to the exterior of components is covered in Appendix E.

Microbes can be introduced into air handling systems in a variety of ways, especially through unfiltered air that contains dust particles. Rainwater splash can also introduce microbes, as can water spray borne by wind. MIC is a potential problem where contamination from untreated water or soil may have introduced the microbes into the gas bearing system in sufficient quantities to cause MIC. Air and gas systems are only affected where stagnant conditions exist in wetted locations (i.e., the pooling of an 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 in Appendix G.

General wear and fretting are, therefore, not applicable to the equipment covered by this tool, with the exception of elastomers, addressed separately in Section 3.5.

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 to resist 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. 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 as 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°F. The susceptibility decreases rapidly as the temperature varies above and below 70°F [4, 6]. Alloying steels with nickel or molybdenum reduces hydrogen embrittlement susceptibility [4, 6]. The stainless steels 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°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°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. However, due to the typical operating temperature ranges of gas systems, IGA is generally not a concern for these systems. 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 SCC.

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 renders 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.

SCC of Stainless Steel (Wrought and Cast)

SCC has occurred in stainless steel, typically in water systems containing dissolved oxygen, sulfates, fluorides, or chlorides. 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]. In general, SCC very rarely occurs in stainless steels below 140°F [1]. However, with a harsh enough environment (for example, significant contamination with halogens), SCC can occur in austenitic stainless steel at ambient temperature.

For the gas atmospheres covered by this tool, a concern arises when moisture-containing contaminants concentrate, resulting in an environment conducive to SCC. The contaminants affecting stainless steel include sea water, chloride solutions, hydrogen sulfide, and sodium hydroxide [5]. The user of this tool should determine from plant-specific operating experience if such concentrations of contaminants have occurred at the plant, and if such concentrations are likely to occur in the future.

SCC of 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. 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].

SCC of nickel-base alloys has been found to occur in three types of environments: high temperature halogen ion solutions (e.g., chlorides in the percent range), high temperature waters, and high temperature alkaline environments, especially above 400°F. In addition, SCC has been detected in liquid metals, near-ambient temperature polythionic acid solutions, and environments containing acids and hydrogen sulfides (H_2S). The conditions that promote SCC in nickel-base alloys are much more severe than those that promote SCC of the common stainless steels [23].

The air and gas environments covered by this tool do not typically include sufficient contaminants and/or temperature to result in SCC of nickel-base alloys in wetted locations. As such, SCC of nickel-base alloys is not an applicable aging mechanism in the air and gas environments covered by this tool.

SCC of Aluminum and Aluminum Alloys

Pure aluminum is not susceptible to SCC; however, aluminum alloys containing more than 12% zinc or more than 6% magnesium are very susceptible to cracking under mild corrosive environments [5]. SCC of aluminum alloys is characteristically intergranular. Research indicates that water or water vapor is the key environmental factor required to produce SCC in aluminum alloys. Halide ions have the greatest effect in accelerating attack, with chloride the most important halide ion because it is a natural constituent of marine environments and is present in other environments as a contaminant. Aluminum alloys in the 2xxx, 5xxx, and 7xxx wrought series are the least resistant to SCC, while the resistance of casting alloys (xxx.x series) is sufficiently high that cracking rarely occurs in service [23].

SCC of Copper and 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 (NH_3) and ammonium (NH_4^+) salts are the corrosive substances most often associated with SCC of copper alloys. These compounds are sometimes present in the atmosphere; in other cases they are in cleaning compounds or chemicals. Both oxygen and moisture are necessary for ammonia to be corrosive to copper alloys; carbon dioxide is also thought to contribute to the process in NH_3 atmospheres. Moisture films on metal surfaces will dissolve significant quantities of NH_3, even from atmospheres with low NH_3 concentrations [4, 5, 23]. Brass containing less than 15% Zn is highly resistant to SCC, even under severe conditions. Additionally, brass is susceptible to SCC in moist air containing trace amounts (0.05 to 0.5 vol%) of sulfur dioxide (SO_2) [23].

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.

However, the nuclear plant air/gas environments addressed by this tool typically do not contain detectable amounts of ammonia, ammonium salts, or sulfur dioxide. As such, SCC of copper and copper alloys is not a concern in air and gas environments unless plant-specific operating experience indicates detectable amounts of ammonia and ammonium compounds (e.g., due to organic decay, bird excreta, or cleaning solvent) or sulfur dioxide (e.g., in industrial areas). For plants with such operating experience, SCC of high zinc (> 15% Zn) brasses and aluminum bronzes (e.g., > 8%Al) are a concern in moist (e.g., humid) and wetted locations.

3.2.3 Vibration

Material fatigue resulting from vibration has been observed in the nuclear industry and can result in crack initiation and growth. Vibration induced fatigue is fast acting and typically detected early in a component's service life and is corrected to prevent recurrence. Corrective actions usually involve modifications to the plant such as the addition of supplemental restraints to a piping system, the replacement of tubing with flexible hoses, or the isolation/elimination of the vibration source when possible. Based upon these considerations, cracking due to vibration fatigue is not considered an applicable aging effect for the period of extended operation of the plant but is a design/installation/maintenance issue rather than an aging effect.

3.2.4 Mechanical/Thermal Fatigue

Aging mechanisms of mechanical and thermal fatigue are evaluated separately in Appendix H.

3.3 Reduction of Fracture Toughness

The fracture toughness of wrought austenitic stainless steel, cast austenitic stainless steel (CASS), and nickel-base alloys is typically higher than that of 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].

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°F) [23]. More recent studies have indicated 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. At lower temperatures, the time required for failure increases as does the associated minimum required stress level necessary to cause embrittlement [29]. Based on work discussed in Reference 29, 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 the steel is exposed to temperatures above 400°F.

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 Change in Material Properties/Cracking – Non-Metals

Glasses

Because most silicate glasses have a high resistance to corrosion in normal environments, glass per se is frequently considered to be an inert substance. Silica is almost insoluble in an aqueous environment except at temperatures in excess of 482°F. Acid attack of soda-lime and borosilicate glass compositions is minimal due to the formation of a protective, highly siliceous surface layer, except for hydrofluoric and phosphoric (at high temperatures) acids [24]. Air and gas systems at nuclear plants do not typically contain contaminants that could concentrate and chemically attack glass.

"Weathering" is a term commonly given to the attack of glass surfaces by atmospheric gases and moisture whereby the surface of the glass becomes dimmed, fogged, and in extreme cases, pitted (high humidity or exposure to alternating cycles of moisture condensation and evaporation can leach alkalis from the surface that react with water and create a very-high pH environment on the surface of the glass that can cause the silicate network to dissolve and visible deposits to form [25]). But with most common compositions (i.e., soda-lime glasses), increased surface alkalinity and enhancement of the attack are needed to cause problems. High silica (e.g., > 96%), borosilicate, and aluminoborosilicate glasses are fully resistant to the weathering phenomenon [24]. Since the air and gas systems for nuclear plants do not contain contaminants that could concentrate and enhance alkaline attack of glasses, chemical degradation or hydrolysis of glass is not an applicable aging mechanism in the environments addressed by this tool.

Plastics

The environment can be a severely limiting factor in the selection and use of plastic materials. The differences between an office and an industrial environment are as significant as the differences between an indoor and an outdoor exposure, with four critical parameters for proper selection: operating temperature, stress level, chemical exposure, and adjoining materials [26]. In air systems, the temperatures to which the surfaces of any plastics are exposed are dictated by the ambient conditions in the location and by internal temperatures (such as in HVAC systems or air start systems). Stress levels are assumed to be adequate for degradation since determination of the actual residual, or molded-in, stresses is not feasible for the purposes of this tool.

The chemical resistance of many engineering plastics is excellent. Plastics are used routinely in environments in which metals would rapidly fail. However, most plastics have specific weaknesses in terms of chemical attack. Failure of plastics due to chemical exposure can be classified as plasticization, chemical reaction, and environmental stress cracking. Plasticization requires exposure to a fluid with which a given plastic is somewhat miscible. Chemical reactions occur between a plastic and an environmental substance that lowers molecular weight or otherwise degrades mechanical properties. Environmental stress cracking is a phenomenon in which a stressed part develops crazing and cracking from exposure to an aggressive substance [26].

Chemical environments can actually degrade a polymer (plastic) by breaking down the polymer chains and altering the material properties. Certain polymer types are more susceptible than others to specific degradation mechanisms, which can include hydrolysis, thermal degradation, oxidation, and photo-degradation, but all polymers can be degraded by at least one mechanism. With exposure to aqueous environments, hydrolytic degradation of susceptible polymers can occur at very slow rates but can become perceptible at conditions of either low (<4) or high (>10) pH. Thermal degradation of susceptible polymers (e.g., high molecular weight polymers) can occur upon exposure to elevated temperatures such as experienced during molding or extrusion operations, but would be much slower in end-use environments due to the lower temperature. Oxidation may occur when many polymers are exposed to oxygen-containing environments; however, susceptible polymers typically have additive stabilizers and antioxidants that will preserve polymer properties at least until the additives have been consumed. Ultraviolet (UV) radiation can be the source of energy that will abstract an atom from the polymer backbone and start the oxidation process. Oxidation initiated by UV radiation will result in eventual loss of properties; although plastics exposed to UV typically have chemical additives which retard these processes, these additives eventually will be consumed and the degradation will proceed [27].

Furthermore, polymers such as PVC and PVDF are resistant to seawater environments up to temperatures of 150°F and 270°F, respectively. PVDF is also resistant to moist/wet sulfur dioxide up to temperatures of 200°F, whereas Type 1 PVC is resistant to moist/wet sulfur dioxide up to 100°F [28]. Assuming proper selection, the air and gas environments addressed by this tool do not typically contain contaminants that could concentrate, or experience elevated temperatures that could result in plasticization and environmental stress cracking of plastics. Degradation of plastics by UV radiation and aggressive environments is addressed separately in Appendix E.

Elastomers

For a complete discussion of the aging effects of typical elastomers used in nuclear plants and the associated industry operating experience, the user of this tool is referred to EPRI report 1002950, *Aging Effects for Structures and Structural Components (Structural Tools), Revision 1* [19]. Although the related discussions in EPRI 1002950 are by nature focused on the external surface, the aging mechanisms (and applicability criteria) discussed therein are also applicable to the internal surfaces of elastomers in mechanical systems, such as sealants for ducts in HVAC systems, except as noted below.

While not addressed in EPRI report 1002590, which is focused on sedentary structural components, elastomers in mechanical systems (e.g., joint seals and flexible connections) may also experience wear as a result of their flexible nature and the small vibrations and/or movement of rotating components (e.g., fans). As such, loss of material due to wear of elastomers materials may be a concern. However, this concern is dependent on the specific elastomer (for which abrasion resistances vary) and condition, and thus requires plant-specific consideration. As described in Section 3.2.3, significant vibration and movement of components is typically detected and corrected early in component life (a design issue).

3.6 Summary of Potential Aging Effects

Table 4-1 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. Figure 1 provides a depiction of the corresponding logic and decision points for the various aging mechanisms that are applicable in air and/or gas internal environments.

Additionally, EPRI report 1002590 [19] addresses the potential aging effects for elastomers, including the conditions necessary for the effects to be manifested. That information is not duplicated in this tool. However, due to their flexibility, wear of elastomers may be a potential aging mechanism for elastomers.

3.7 Operating History

An operational history review was performed using NPRDS, its successor EPIX, and 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 up through 1997. From 1997 through the present, this data is contained in the Equipment Performance and Information Exchange (EPIX) system. The purpose of a review of this material is to assure that failures of in-scope equipment due to aging are 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 Air/Gas Tool encompasses numerous systems, environments, and materials. As a result, it would be extremely time consuming to sort and review all NPRDS and EPIX entries that cover this entire spectrum of combinations. The search criteria included all NPRDS and EPIX 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 / DAMPER, HEATER, BLOWER, 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 (included 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 (included 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, Diesel Starting Air-GE, and Control Room Air Conditioning-GE

The purpose of the NPRDS / EPIX searches was to identify equipment failures resulting from the effects of aging. As the EPIX search was conducted for Revision 3 of these tools, the above NPRDS search conditions were matched as closely as possible for the EPIX queries. Although the EPIX search conditions are not an exact match for the NPRDS conditions, a conservative approach was taken when determining the appropriate search conditions. Although NPRDS and EPIX 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, 581 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 581 items identified, 304 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 121 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 61 entries.

There were 55 entries that represented equipment failures resulting from the effects of aging. Table 3-1 identifies the number of records attributable to the various aging mechanisms and includes a percentage of the total for each category.

Table 3-1 NPRDS / EPIX Search Summary

FAILURE CAUSE	NO. OF ENTRIES	% OF TOTAL
Wear	12	22
Vibration	7	13
Structural Integrity Loss	23	42
Corrosion	11	19
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 of 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 (the 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 that 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, and 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 aftereffects 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 / EPIX 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 / EPIX 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 **not** 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. Of these, 10 were considered to be related, either directly or indirectly, to air and gas system failures. Eight were Information Notices, 1 was a Bulletin, and 1 was a Generic Letter. These entries are discussed briefly below. 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 a 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 (an active component). 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. Problems of air system contamination potentially pose a common mode failure condition. This information notice provides several recommendations to minimize air system contamination problems, 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 from coming in contact with components such as pipes.

Circumferential cracks were observed on piping which was due to brittle fracture caused by the piping temperature having been below its nil ductility temperature. Failures of nitrogen evaporator and isolation valve 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 (Revision 0 and Supplement 1): Air Systems Problems at U.S. Light Water Reactors

This information notice and its supplement provide 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 occurred due to hydrogen embrittlement. All couplings of this type have 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 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 ten industry documents that identified 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 air/gas tool logic.

4. FLOW DIAGRAM/SUMMARY TABLE DEVELOPMENT

4.1 Assumptions

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

1. The gas sources other than air (e.g., hydrogen, nitrogen, carbon dioxide, halon, fluorocarbons) evaluated as internal environments for this tool are clean dry sources with no significant levels of contaminants such as chlorides, sulfates, or oxygen unless they are used as a cover gas/blanket for a stored liquid, where contaminants may concentrate out of the liquid due to alternate wetting and drying. Another exception is when replacement gases for halon or fluorocarbons have been used. Some of these gases are corrosive. The flow chart evaluates the applications where fluorocarbon/halon substitutes have been used.

2. Non-metallic "consumable" items (gaskets, O-rings, seals, and sealing compounds) are excluded from aging management and 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 and, as such, are evaluated separately in Appendix B.

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 airborne contaminants and, for the purposes of this tool, it is assumed that these contaminants are present in all but the purest of gases. 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