Incorporation of Corrosion Mechanisms into a State-dependent Probabilistic Risk Assessment

THESIS

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By

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Abstract

The need for extending lifetimes of nuclear power plants and an increased interest in passive safety systems in Generation III+ and small modular reactors has brought a new focus in probabilistic risk assessment (PRA) to the treatment of passive systems, structures and components (SSCs). Although previously thought to play a lesser role in determining plant risk, research and industry experience have shown that degradation mechanisms of passive SSCs increase in importance with extended operating lifetimes.

The case study analyzed in this research involves an accident scenario, in which steam generator tubes degraded by stress corrosion cracking rupture due to depressurization following a steam line break resulting from flow-accelerated corrosion. This study was performed by developing a state-dependent risk model. The model has the capability of using traditional PRA tools such as event trees and fault trees to determine a state-dependent core damage frequency. Unlike traditional PRA, which emphasizes active components, this methodology was used with a mechanistic aging model of a passive component. In addition, the model considers the effectiveness of the surveillance program and may be further developed to account for the possibility of component rejuvenation. Thus, the model allows for a time-dependent assessment of plant aging on risk.

The application of the model to the Zion Nuclear Power Station has indicated that the maximum core damage frequency over the plant lifetime for a steam line break-
induced tube rupture would occur in the 20th year of plant operation. The model also predicts the time progression of tube plugging and the frequency of spontaneous steam generator tube ruptures. Based on historical data, the rates of degradation calculated in the analysis appear to be reasonable, but somewhat conservative.
Acknowledgments

I want to thank Dr. Tunc Aldemir, Dr. Richard Denning, and Dr. Jinsuo Zhang for their continuing support, guidance, and insights provided throughout the course of this project.

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Publications


Fields of Study

Major Field: Nuclear Engineering
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<td>Anticipated Transient Without Scram</td>
</tr>
<tr>
<td>BNL</td>
<td>Brookhaven National Laboratory</td>
</tr>
<tr>
<td>BWR</td>
<td>Boiling Water Reactor</td>
</tr>
<tr>
<td>B&amp;W</td>
<td>Babcock &amp; Wilcox Company</td>
</tr>
<tr>
<td>CCDF</td>
<td>Complementary Cumulative Distribution Function</td>
</tr>
<tr>
<td>CDF</td>
<td>Core Damage Frequency</td>
</tr>
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<td>CGR</td>
<td>Crack Growth Rate</td>
</tr>
<tr>
<td>DET</td>
<td>Dynamic Event Tree</td>
</tr>
<tr>
<td>ECCS</td>
<td>Emergency Core Cooling System</td>
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<tr>
<td>EPRI</td>
<td>Electric Power Research Institute</td>
</tr>
<tr>
<td>ET</td>
<td>Event Tree</td>
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<tr>
<td>FAC</td>
<td>Flow-Accelerated Corrosion</td>
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<tr>
<td>FEA</td>
<td>Finite Element Analysis</td>
</tr>
<tr>
<td>FT</td>
<td>Fault Tree</td>
</tr>
<tr>
<td>IGSCC</td>
<td>Intergranular Stress Corrosion Cracking</td>
</tr>
<tr>
<td>IGA</td>
<td>Intergranular Attack</td>
</tr>
<tr>
<td>INL</td>
<td>Idaho National Laboratory</td>
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<tr>
<td>IPE</td>
<td>Individual Plant Examination</td>
</tr>
<tr>
<td>IPEEE</td>
<td>Individual Plant Examination for External Events</td>
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<tr>
<td>ISFSI</td>
<td>Independent Spent Fuel Storage Installation</td>
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</table>
LBB  Leak-before-break
LOCA  Loss Of Coolant Accident
LTP  License Termination Plan
LWR  Light Water Reactor
MA  Mill-annealed
MRP  Materials Reliability Program
MSIV  Main Steam Isolation Valve
NDE  Nondestructive Examination
NPP  Nuclear Power Plant
NPRDS  Nuclear Plant Reliability Data System
NRC  United States Nuclear Regulatory Commission
NSSS  Nuclear Steam Supply System
OD  Outside Diameter
ODSCC  Outside Diameter Stress Corrosion Cracking
OSyS  Optimized Systems and Solutions
OTSG  Once-Through Steam Generator
PIRT  Phenomena Identification and Ranking Table
PMDA  Prospective Materials Degradation Assessment program
PNNL  Pacific Northwest National Laboratory
PRA  Probabilistic Risk Assessment
PWR  Pressurized Water Reactor
PWSCC  Primary Water Stress Corrosion Cracking
RCS  Reactor Coolant System
RIRIP  Risk-Informed Regulation Implementation Plan
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tr>
<td>RPP</td>
<td>Risk-informed, Performance-based Plan</td>
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<td>RPV</td>
<td>Reactor Pressure Vessel</td>
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<tr>
<td>RSG</td>
<td>Recirculating Steam Generator</td>
</tr>
<tr>
<td>RSS</td>
<td>Reactor Safety Study</td>
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<td>RTZ</td>
<td>Roll Transition Zone</td>
</tr>
<tr>
<td>SAPHIRE</td>
<td>Systems Analysis Programs for Hands-on Integrated Reliability Evaluations</td>
</tr>
<tr>
<td>SAR</td>
<td>Safety Analysis Report</td>
</tr>
<tr>
<td>SCC</td>
<td>Stress Corrosion Cracking</td>
</tr>
<tr>
<td>SG</td>
<td>Steam Generator</td>
</tr>
<tr>
<td>SGTR</td>
<td>Steam Generator Tube Rupture</td>
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<tr>
<td>SLB</td>
<td>Steam Line Break</td>
</tr>
<tr>
<td>SSC</td>
<td>Systems, Structures, and Components</td>
</tr>
<tr>
<td>TGSCC</td>
<td>Transgranular Stress Corrosion Cracking</td>
</tr>
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<td>TMI</td>
<td>Three Mile Island</td>
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<tr>
<td>TT</td>
<td>Thermally Treated</td>
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<tr>
<td>TW</td>
<td>Through-wall</td>
</tr>
<tr>
<td>UTS</td>
<td>Ultimate Tensile Strength</td>
</tr>
<tr>
<td>YS</td>
<td>Yield Strength</td>
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Chapter 1: Introduction

The thesis consists of seven chapters. Chapter 1 starts by explaining the motivation and research objectives for this study (Section 1.1), briefly discusses the review preceding the quantitative portion of the analysis (Section 1.2), provides an overview of historical background on probabilistic risk assessment (PRA) (Section 1.3), commonly used PRA tools and codes (Section 1.4), current PRA focus (Section 1.5), and dynamic PRA (Section 1.6). Chapter 2 introduces the accident scenario along with initial assumptions and references the model plant and related documentation used for the analysis. Chapter 3 provides information about the main steam isolation valve and its role in the accident scenario. Chapter 4 focuses on flow-accelerated corrosion leading to a steam line break, which serves as the accident-initiating event. Chapter 5 discusses stress corrosion cracking occurring in the steam generator tubes and associated degradation rate model. Chapter 6 establishes the basis for the overall state-dependent risk model, presents case results and offers their interpretation from the viewpoint of traditional PRA. Finally, Chapter 7 summarizes key findings and conclusions, examines limitations of this project, identifies the need for future studies, and discusses a possible application of this study to plant-specific PRAs.
1.1. Motivation and Research Objectives

The research presented in this document was motivated by efforts to integrate aging mechanisms of passive systems, structures, and components (SSCs) into probabilistic risk assessment driven by:

- an industry-wide movement towards extended life cycles of nuclear power plants, and
- interest in passive safety system implementations in Generation III+ reactors and small modular reactors.

The research findings described here serve as an intermediate step towards fully incorporating aging mechanisms into dynamic PRA. Rather than performing a full dynamic PRA, the purpose of the present study was to:

- analyze a hypothetical accident, not only initiated by failure of a passive component subjected to corrosion, but also causing failure of a passive safety-related component that had been weakened as the result of a different corrosion process, and
- demonstrate the use of mechanistic degradation models in time-dependent assessment of plant aging on risk.

The first of these objectives involves an accident scenario, in which a bypass of containment results from a steam generator tube rupture (SGTR) induced by a steam line break (SLB) outside the containment. The choice of mechanisms affecting steam generator tubes and carbon steel piping is explained in Section 1.5.3.
The second objective is fulfilled by developing a state-dependent PRA methodology based on classical PRA tools such as event trees and fault trees. These tools are described in Section 1.4.1 and 1.4.2.

The work presented in this thesis is a part of a larger project undertaken by The Ohio State University in collaboration with Pacific Northwest National Laboratory (PNNL) aimed at developing a methodology for passive component reliability modeling in a multi-physics simulation environment [1].

1.2. Review Process

The review process preceding the quantitative analysis performed in this research study led to:

- identifying passive SSCs of greatest concern in PWRs and the degradation mechanisms to which they are subjected (Section 1.5.3),
- selection of the Zion Nuclear Power Station as a reference plant for the study and collection of necessary plant data largely provided through NUREG-1150 and NUREG/CR-4550 Vol. 7. (Section 2.1.2 and 2.2.1),
- formulation of the response of a typical PWR to a hypothetical accident scenario represented with an event tree (Section 2.2.2),
- an understanding of concepts underlying flow-accelerated corrosion and stress corrosion cracking as well as the quantitative modeling of progression rates (Chapter 4 and Chapter 5).
This review enabled the development of a damage progression model of a steam generator and consequently, the development of a state-dependent PRA methodology.

1.3. Historical Background

1.3.1. Probabilistic Risk Assessment Origins and WASH-1400

Early regulations developed by the U.S. Atomic Energy Commission were deterministic in nature and did not account for probabilistic estimates of risk. The Reactor Safety Study (RSS), published in 1975 as WASH-1400, was the first comprehensive probabilistic risk assessment of nuclear power plants. The strength of this report lay in its probabilistic quantification of accidents that posed health and safety concerns to the public [2]. WASH-1400 formulated the concept of accident scenarios as a triplet of frequency, consequence, and scenario identifier [3]. In addition, WASH-1400 was the first report to use complementary cumulative distribution function (CCDF) to display the numerical results of risk and introduced nomenclature that is still widely used today [3]. Although PRA has much progressed since WASH-1400, mainly through the work performed as part of NUREG-1150, it is considered “the milestone study” in the development of PRA techniques [3].

The current regulatory approach, embraced by the U.S. Nuclear Regulatory Commission (NRC), is to gradually move away from regulations based on deterministic and prescriptive requirements to risk-informed and performance-based regulations [2]. This approach began in 1994 with the Probabilistic Implementation Plan, which focused
on PRA-related activities. In 2000, Risk-Informed Regulation Implementation Plan (RIRIP) was developed and then replaced by Risk-Informed, Performance-Based Plan (RPP) in 2007 [2]. Risk-informed regulations incorporate information about accident scenarios, their likelihood and associated consequences, or risk [4].

1.3.2. NUREG-1150: An Assessment for Five U.S. Nuclear Power Plants

By the late 1970s, improvements in PRA methodology had been developed related to advanced methods for assessing the frequencies of accidents, improved means for collection and use of plant operational data, and advanced methods for assessing the impacts of human errors and other common-cause failures [5]. A key advancement was made by the NRC’s Severe Accident Research Program and its reassessment of the technical bases for estimating source terms published in NUREG-0956. A source term is defined as the quantity, timing, and characteristics of radioactive material released to the environment following a severe accident [6]. Source term assessment is commonly applied to regulatory decisions such as emergency planning, evaluation of safety features, environmental impact statements, etc. The Severe Accident Research Program advanced this area significantly from the technology available during the RSS. The improvements came from using an extensive database from severe accident research programs initiated after the Three Mile Island (TMI) accident, integrated computer codes for modeling key aspects of fission product behavior under severe accident conditions, and mechanistic codes that bridged the gap between the database and the NRC’s Source Term Code Package [6]. The Source Term Code Package was developed to provide realistic
estimates of source terms without any intentional conservative margins. This code was used to treat source terms in NUREG-1150 risk study.

One of the recommendations following the TMI accident in 1979 was to analyze severe accidents stemming from multiple system failures in the licensing process and to use probabilistic safety goals as a benchmark for defining the required level of plant safety. In response to these developments, the NRC began a new, comprehensive PRA study and published its results in the NUREG-1150 report.

NUREG-1150 examined the risks from severe accidents in five commercial nuclear power plants (NPPs) in the United States. Two of these plants (Peach Bottom, Grand Gulf) were boiling water reactors (BWRs) and three of these (Surry, Zion, Sequoyah) were pressurized water reactors (PWRs). The plants differed from each other based on their design and geographic location. They were purposely selected for PRA analysis to reflect a wide spectrum of plant designs and operating conditions found across the United States. Table 1 lists the plants analyzed in NUREG-1150.

<table>
<thead>
<tr>
<th>Plant</th>
<th>Design</th>
<th>Location</th>
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<tbody>
<tr>
<td>Surry Power Station</td>
<td>Westinghouse-designed three-loop reactor in subatmospheric containment building</td>
<td>Williamsburg, VA</td>
</tr>
<tr>
<td>Zion Nuclear Plant</td>
<td>Westinghouse-designed four-loop reactor in a large, dry containment building</td>
<td>Chicago, IL</td>
</tr>
<tr>
<td>Sequoyah Nuclear Power Plant</td>
<td>Westinghouse-designed four-loop reactor in an ice condenser containment building</td>
<td>Chattanooga, TN</td>
</tr>
<tr>
<td>Peach Bottom Atomic Power Station</td>
<td>General Electric-designed BWR-4 reactor in a Mark I containment building</td>
<td>Lancaster, PA</td>
</tr>
<tr>
<td>Grand Gulf Nuclear Station</td>
<td>General Electric-designed BWR-6 reactor in a Mark III containment building</td>
<td>Vicksburg, MS</td>
</tr>
</tbody>
</table>

Table 1. Five commercial nuclear power plants assessed in NUREG-1150 [5]
The report quantified risks based on then-current design, operational characteristics, related failure data, and severe accident phenomenological information [5]. The work performed as part of NUREG-1150 proved to be a significant improvement from the PRAs done in WASH-1400. NUREG-1150 was a much more extensive assessment and involved new and improved PRA methodology. One of the key differences from the RSS report was the inclusion of quantitative estimates of risk uncertainty within the risk process. The superficial treatment of uncertainty was a major criticism of WASH-1400. Furthermore, the assessments completed for NUREG-1150 provided the NRC with an updated overview of risks. NUREG-1150 showed that the risks to the public from the five nuclear power plants were lower than the estimates obtained for the two plants examined for WASH-1400 in 1975. The individual early fatality and latent cancer fatality risks from internally initiated events, and the fire-initiated accidents at Surry and Peach Bottom, were found to be well below the NRC safety goals [5].

NUREG-1150 identified main issues of interest in risk mitigation for BWRs and PWRs. More specifically, anticipated transients without scram (ATWS) and station blackout were found to be of greatest importance in BWRs. In the case of PWRs, the issues were much more varied and included electrical power system disturbances, small loss-of-coolant accidents (LOCAs), loss of coolant support systems, ATWS, interfacing-system LOCAs, and SGTRs, in which reactor coolant is released outside the containment [5]. In short, one of the key findings was that each plant’s unique design leads to specific vulnerabilities.
In addition, NUREG-1150 laid a foundation for future PRA-related analyses. The report, available to the public, provides a set of PRA models and results that can support the ongoing prioritization of potential safety issues and research [5]. This work and its supporting documents provide a wide spectrum of phenomenological and operational data. The study has led to the development of more rapid, reduced-cost Level 1 PRA methodology and possible future reduction in the cost of containment analysis [7]. Moreover, NUREG-1150 broadly outlines accident management. The four steps required for effective severe accident management include 1) preventing of core damage, 2) terminating the progress of core damage if it begins and retaining the core within the reactor vessel, 3) maintaining containment integrity as long as possible, and 4) minimizing the consequences of offsite releases [5].

1.3.3. Independent Plant Evaluations

One of the outcomes of NUREG-1150 assessments was the recognition that each nuclear plant has a unique design and features, which influence risk calculations. The report explicitly states that the five plants examined are not to be used to describe all plants in the United States due to these differences. The risks related to specific plant designs led to the NRC-mandated individual plant examination (IPE) process in all U.S. nuclear power plants. IPE requires all plants to complete a risk analysis or a more focused study of the unique features of a particular plant identifying the specific vulnerabilities of that plant to severe accidents [8]. Regardless whether a plant chose to perform a more limited study to satisfy the IPE requirements, all nuclear power plants now have a Level 1
PRA. Subsequent to the IPE studies, all plants were required to provide a limited consideration of external events in the IPEEE (IPE for External Events) program.

1.4. Probabilistic Risk Assessment

1.4.1. Risk Assessment Tools

As prescribed by NUREG-1150, a full-scope PRA is comprised of five steps: 1) systems analysis, 2) accident progression analysis, 3) source term analysis, 4) consequence analysis, and 5) risk integration. Systems analysis consists of determining the likelihood and nature of accidents involving core damage. An investigation of core damage processes and impacts on containment is performed during accident progression analysis. A source term analysis involves an assessment of radionuclide release and transport to the environment. Consequence analysis is a calculation of health effects. The results of these analyses are assembled to determine risk during risk integration.

Furthermore, PRA can be divided into three levels. Level 1 PRA is tasked with predicting the frequency of core damage. Level 2 PRA, in addition, includes the analysis of accident progression, containment failure, and most importantly, the release of radionuclides to the environment. Level 3 PRA additionally incorporates calculation of human health effects.

Event trees (ET) and fault trees (FT) are two PRA tools that allow schematic representation of system components, associated probabilities and dependencies. An event tree is an inductive approach to identify a variety of scenarios associated with
combinations of failed systems. The probability of success or failure of each branch of the event tree is typically determined using a fault tree. Safety systems frequently consist of several components, each with its own probability of failure. Thus, a fault tree is a way to decompose a system, to a reasonable degree, into its basic components and assess the probability of root element failures and their contribution to the overall system failure. A system is typically analyzed in a top-down approach. Assuming a failure, a system is first decomposed into subsystems, and then into critical components. To depict the complexity and dependencies of subsystems and components a fault tree is represented using logic gates.

1.4.2. PRA Codes

Nuclear power plants, being highly complex engineering systems, necessitate the use of advanced computer codes that allow PRA analysis in a robust and timely manner. For this purpose, the Idaho National Laboratory (INL) has developed the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. This application can be used to model a system’s response to initiating events and quantify associated consequential outcome frequencies [9].

Due to a large number of features and its relative simplicity, SAPHIRE is widely used by the NRC, national laboratories, research institutions, private sector, and foreign countries [9]. This code enables the user to analyze both internal and external initiating events and to perform an assessment of a nuclear reactor operating at low power, full power, or during shutdown conditions [9]. SAPHIRE has features that enable
identification of core damage contributors (Level 1 PRA) and containment failure during a severe accident leading to releases (Level 2 PRA) [9]. However, this code can be used for Level 3 PRA in a limited manner only. There is a large array of other codes that originated at different institutions and specialize in specific PRA tasks. Table 2 provides a list of some of these codes and their application areas.

<table>
<thead>
<tr>
<th>Code</th>
<th>Application Area</th>
<th>Origin</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAFTA</td>
<td>Standard PRA</td>
<td>Optimized Systems and Solutions (OSyS)/EPRI</td>
</tr>
<tr>
<td>RiskSpectrum PSA</td>
<td>Standard PRA</td>
<td>Scandpower Risk Management</td>
</tr>
<tr>
<td>RISKMAN</td>
<td>Standard PRA</td>
<td>ABS Consulting</td>
</tr>
<tr>
<td>MAAP4</td>
<td>Modeling of severe accident phenomena</td>
<td>EPRI</td>
</tr>
<tr>
<td>RELAP5</td>
<td>Modeling of design basis accidents and conditions within the vessel prior to severe fuel damage [10]</td>
<td>Idaho National Laboratory</td>
</tr>
<tr>
<td>MELCOR</td>
<td>Modeling of severe accident processes including threats to containment integrity and radionuclide release to the environment</td>
<td>Sandia National Laboratory</td>
</tr>
<tr>
<td>ICARE/CATHARE</td>
<td>Modeling of severe accidents in PWRs including core degradation and thermal hydraulics</td>
<td>Institut de radioprotection et de sûreté nucléaire (IRSN)</td>
</tr>
</tbody>
</table>

Table 2. PRA and PRA-support codes and their applications

1.5. Current PRA Focus

1.5.1. Plant Life Extension

As specified by the Atomic Energy Act of 1954, nuclear power plants were originally licensed to operate for 40 years. However, this operating period was based on
economic and antitrust considerations rather than on the technical limitations of nuclear facilities [11]. As the industry began approaching the 40-year mark, the NRC and the nuclear power plant operators undertook activities to allow plant life extension to 60 years. This was justified by the relatively low cost of updating and enhancing surveillance of existing plants when compared to the cost of building a new nuclear power plant. There are 104 commercial nuclear reactors in the United States. As of February 2011, 62 reactor licenses were renewed and 20 more were under review [12]. Plant life extension is not an issue exclusive to the United States, but also of interest to countries with long-standing nuclear industries such as France, Great Britain, Japan, and Russia. It is also worth to mention that the global nuclear industry is looking beyond a 60-year operating cycle and researching the feasibility of extending existing power plant operations to 80 years.

1.5.2. Aging Considerations

In the past, PRA programs emphasized issues related to active components, as they were believed to have the greatest impact on risk. In comparison, passive SSCs were thought to be much more reliable. However, over decades of operation various material degradation mechanisms such as irradiation damage, fatigue, cracking, erosion, corrosion, etc. have led to failures that required plant shutdown [13]. As the nuclear fleet enters the extended lifetime, new degradation mechanisms are discovered and passive systems are increasingly growing in importance. Safety concerns related to passive systems are not only important from a perspective of extended power plant life cycles,
but also because of interest in Generation III+ and small modular reactors. For instance, Babcock & Wilcox Company plans to deploy the mPower reactor with passive safety systems as one of its key features [14].

Passive SSCs are commonly tested through surveillance programs that use methods such as eddy current testing or ultrasonic testing. However, such evaluations are subject to errors. In certain cases, the geometry of the SSCs prevents successful testing [13]. In addition, these testing methods may fail to capture all material degradations. For instance, eddy current inspection of SG tubes experiences difficulty in sizing of cracks in certain tube locations.

1.5.3. Prioritization of Degradation Issues

Over the past decades, the nuclear operators have accumulated large quantities of service data that provide insights into issues related to maintenance and reliability of SSCs. The importance and failure likelihoods of passive components can be inferred from such records. The Proactive Materials Degradation Assessment (PMDA) program, facilitated by Brookhaven National Laboratory (BNL), served to identify materials and components in specific light water reactor (LWR) systems where future degradation may occur [15]. The program developed an approach for identifying areas of concern based on the knowledge of an international panel of eight experts and the use of a Phenomena Identification and Ranking Table (PIRT) process [15]. The panel drew conclusions from information on the materials, fabrication process, and operational environment for hundreds of different parts of systems in a Westinghouse four-loop PWR design and a
BWR-4 design [15]. Based on a thorough review of industry data and records, the panel
has determined that stress corrosion cracking (SCC) of Alloy 600 in the SG tubes and
flow-accelerated corrosion (FAC) of carbon steel components are of greatest concern in
PWRs [15].

1.6. Dynamic PRA

1.6.1. Time-dependent Analysis

The analysis of passive SSCs in PRA is complicated due to their relatively slow
degradation mechanisms and their changing failure probability with time. Current
methods of reliability quantification rely mostly on plant service data rather than on
physics-based models. Furthermore, incorporation of passive SSCs into risk assessment is
complicated by the possibility of component rejuvenation before failure and dependence
on successful surveillance [1]. Traditional PRAs are static in nature and do not account
for time-dependent phenomena. However, dynamic PRA offers a methodology allowing
for time-based phenomenological model of a system evolution along with its stochastic
behavior to account for possible dependencies between failure events [16].

Although traditional ET/FT methodology provides simplicity and clarity in
understanding results, it also carries a number of limitations. The strongest of these is
related to the inability of ET/FT framework to account for the impact of complex
interactions between human actions, hardware, firmware, and software on the stochastic
system behavior [16]. Dynamic PRA offers a unified approach towards uncertainties
resulting from stochastic events (aleatory uncertainties) and lack of information about processes (epistemic uncertainties).

Dynamic PRA methodologies can be categorized into three groups: continuous-time methods, discrete-time methods, and methods with graphical interfaces. A comprehensive treatment of these methods is provided in [16]. Nevertheless, all three methodologies require time-dependent system models, possible normal and abnormal system configurations, and transition rates among these configurations [16]. One of the most popular approaches in dynamic PRA is the dynamic event tree (DET), a tool of the discrete-time methodology. In traditional ETs, the analyst specifies the sequence of system responses to initiating events. In contrast, DETs utilize a time-dependent model of system evolution and branching conditions to determine the timing and sequence of system responses [1, 16].

1.6.2. Markov Models

Dynamic PRA in its time-based treatment of events often employs a Markovian representation of the system and its conditions. A Markov chain describes a system or component in terms of discrete states linked to each other via transition rates. Each state can be described with a time-dependent probability. The transition rates represent the possibility of moving from one state to another and can be constant or time-dependent functions. Markov chains can be expressed using differential equations based on the number of states and transition rates. The solution to the differential equations provides the analyst with a time-based probability of the system being in a particular state.
It is important to mention that during the progression of the system, the current state depends only on the previous state of the system and does not consider any prior history. Markov process is thus a memoryless process and systems exhibiting this particular form are termed to have Markov property.

An example depicting a passive component using the Markov framework is shown in Figure 1. Here, a pipe is modeled to have four distinct possible conditions: no flaw, flaw, leak, and rupture/large leak. These states represent a pipe’s progression from a new or rejuvenated component to a state of failure. The states are linked through five transition rates describing actions involving the pipe such as crack initiation, detection, tube repair, replacement, etc.

Figure 1. Markov chain representation of pipe lifetime (adapted from [1])
1.6.3. PNNL Approach to Transition Rates

A significant study using a state transition mode was performed by PNNL in an attempt to incorporate aging of passive components into PRA [14, 17]. The analysis focused on crack growth in welds of dissimilar metals caused by SCC. Unwin et al. proposed a model that considered progressive degradation of components through a series of discrete states: initial crack, detectable flaw, leak, and rupture [17]. A diagram showing the proposed multi-state model is shown in Figure 2.

The strength of this approach lies in the treatment of the transition rates between states. Typically, these rates are quantified using degradation rates inferred from service data and restoration rates based on estimation of detection and repair probabilities [17]. A major advantage of such approach is the ability to evaluate surveillance methods such as leak detection and nondestructive examination (NDE) [14]. However, [17] used physics-based degradation models to determine the transition rates. Since this approach resulted in transition rates dependent on system history and hence violated Markov property, the state transition model was transformed to a Markov model through the use of auxiliary variables, which also substantially increased the number of equations to be solved [17].
Figure 2. Physics-based multi-state model of crack growth due to SCC (adapted from [14])
Chapter 2: Bypass Scenario Involving a Steam Line Break outside Containment

Section 2.1 introduces the hypothetical accident initiation and progression at the Zion Nuclear Power Station, the reference plant selected for this study. In addition, Section 2.2 identifies the sources of data (NUREG-1150 and NUREG/CR-4550 Vol. 7) used in formation of the event tree representing the response of safety systems to the initiating event.

2.1. Accident Scenario

2.1.1. Accident Initiation and Progression

The accident scenario selected for analysis involves failures of passive components due to degradation mechanisms for which there has been extensive operational experience. More specifically, in the case studied here, a steam line break outside the containment and downstream of a main steam isolation valve (MSIV) serves as the initiating event. Following a steam line break, the accident continues with a failure of a MSIV and the rupture of a flawed SG tube in the steam generator upstream of the MSIV. Flow-accelerated corrosion of piping in the power conversion system and stress corrosion cracking were selected as the acting degradation mechanisms. The selection of these aging mechanisms is in agreement with the findings of the PMDA program discussed in Section 1.5.3.
Steam lines penetrate the containment wall, which makes it necessary for each line to contain an isolation valve external to the containment. The containment building becomes pressurized if the steam line breaks inside of it. This is a design basis accident analyzed in safety analysis reports (SARs). The containment integrity is not lost if the MSIVs close properly. If the depressurization of the SG leads to rupture of a tube, the reactor coolant system (RCS) begins to depressurize and it becomes necessary to inject emergency core cooling water into the RCS to prevent core damage. The conditional probability of core meltdown should be similar to that seen in small break LOCA scenarios. If an isolation valve fails to close, there will be a modest release of radionuclides to the environment associated with the operating level of radionuclide contamination in the RCS. However, if the emergency core cooling system (ECCS) works in both injection mode and recirculation mode, core meltdown will be avoided.

If the steam line breaks downstream of the isolation valve, the situation is different. If the MSIV fails to actuate and a tube rupture is induced by the increased pressure differential, there is a likelihood of core meltdown with the containment bypassed. In this case, the ECCS is ineffective in the injection phase and fails due to lack of water in the sump when the switch to recirculation occurs. Although the likelihood of this scenario is expected to be very small, it is of particular interest because of the potential for containment bypass and large ensuing consequences.
2.1.2. Model Plant

The chosen scenario of concern is modeled using the Zion Nuclear Power Station as a reference PWR plant. The Zion plant was a two-unit station located on the shore of Lake Michigan. Each of the two units was a four-loop Westinghouse nuclear steam supply system (NSSS) with a rating of 1100 MWe housed in a large, pre-stressed concrete, steel-lined dry containment [5]. The brief history of the plant is provided in Table 3. The piping and instrumentation diagram of the plant is shown in Figure 3.

<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>December 1973</td>
<td>Zion 1 starts commercial operation</td>
</tr>
<tr>
<td>February 13, 1998</td>
<td>Units 1 and 2 are permanently shut down</td>
</tr>
<tr>
<td>September 1, 2010</td>
<td>Facility license is transferred from Exelon to ZionSolutions for decommissioning</td>
</tr>
<tr>
<td>2014 (Estimate)</td>
<td>Completion of fuel transfer to an independent spent fuel storage installation (ISFSI)</td>
</tr>
<tr>
<td>2015 (Estimate)</td>
<td>Submission of license termination plan (LTP)</td>
</tr>
<tr>
<td>2020 (Estimate)</td>
<td>Closure and termination of the site</td>
</tr>
</tbody>
</table>

*Table 3. History of the Zion Nuclear Power Station [5, 18]*
Figure 3. Zion Nuclear Power Station piping and instrumentation diagram (adapted from [5])
2.2. Induced Steam Generator Tube Rupture

2.2.1. Plant-related Documentation

Parts of NUREG-1150 corresponding to the Zion plant and its support document NUREG/CR-4550 Vol. 7 provided enough detail about plant layout and safety systems to reconstruct a hypothetical accident scenario. These sources are listed as [5] and [19]. However, neither of these documents contains information about fault trees associated with specific safety system failures. Furthermore, the steam line break under consideration was not analyzed in NUREG-1150 PRAs [5]. Nevertheless, NUREG/CR-4550 Vol. 7 documents a number of accident scenarios that have similar events to those for the steam line break under consideration, including event trees for small LOCAs, steam generator tube rupture, and steam line break. The information included in this report includes tabulated failure probabilities that helped infer the likelihood of specific system failures and provides insights into the plant safety mechanisms.

2.2.2. Development of Event Tree

The safety functions and associated probabilities of failure on demand described in NUREG/CR-4550 Vol. 7 were used to develop an event tree, shown in Figure 4, for the primary accident of interest resulting from a steam line break. The Top Events and corresponding failure probabilities are summarized in Table 4.
<table>
<thead>
<tr>
<th>Top Event Acronym</th>
<th>Top Event Description</th>
<th>Probability of failure on Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>SLB</td>
<td>Steam line break outside the containment (Initiating Event)</td>
<td>See Chapter 6</td>
</tr>
<tr>
<td>K</td>
<td>Reactor trip</td>
<td>1.8E-4</td>
</tr>
<tr>
<td>M</td>
<td>MSIV failure</td>
<td>See Chapter 3</td>
</tr>
<tr>
<td>TR</td>
<td>Tube rupture given pressure gradient</td>
<td>See Chapter 6</td>
</tr>
<tr>
<td>RW</td>
<td>Refueling water storage tank</td>
<td>2.4E-8</td>
</tr>
<tr>
<td>SS</td>
<td>Safety injection system actuation signal</td>
<td>2.2E-5</td>
</tr>
<tr>
<td>L1</td>
<td>Auxiliary feedwater actuation and secondary cooling</td>
<td>3.4E-5</td>
</tr>
<tr>
<td>HP</td>
<td>High Head Injection/Feed and Bleed</td>
<td>2.1E-8</td>
</tr>
<tr>
<td>R2</td>
<td>Low pressure recirculation</td>
<td>4.6E-4</td>
</tr>
</tbody>
</table>

Table 4. Top events and failure probabilities for the accidents considered

In addition, the event tree shown in Figure 4 was developed based on several assumptions:

- NUREG/CR-4550 Vol. 7 considers scenarios with combinations of AC buses not working. The scenarios considered here assume that all AC buses work properly due to the very low frequency of the scenario, in which any of the three AC buses is not working.
- Failure of a reactor to trip leading to ATWS scenarios is not further analyzed.
- MSIV failure leads to a blowdown of affected SG (secondary side) and depressurization of the steam header. If the faulted SG is one of the two lines that provide steam to the auxiliary feedwater system, only one auxiliary feedwater pump is available. In this case, the probability of failure of auxiliary feedwater increases.
- SGTR results in a small break LOCA.
• An operator can act to depressurize the RCS to slow down the release to the environment caused by leakage of RCS inventory into the turbine building. However, if the auxiliary feedwater system fails, it is necessary to rely on the feed and bleed system at high pressure.

• Since modern seals are less likely to fail, the scenario ignores the possibility of a pump seal LOCA.

Event tree depicted in Figure 4 shows that the first line of response to the steam line break is a reactor trip. Following a successful plant shutdown, the closure of a MSIV leads to a design basis accident resulting in a successful prevention of core meltdown. In case of MSIV failure, if the integrity of SG tubes remains uncompromised, a meltdown is also avoided. However, if the SG tubes rupture, a series of safety functions act to stop core meltdown. Failure of the first line of defense (i.e. supply of water from the refueling water storage tank or high pressure injection) leads to an early core meltdown. The last line of defense is the low pressure recirculation. However, in case of a SLB, there is no water in the sump that would permit recirculation to work properly. In that case, even if the system functions properly from a mechanical standpoint, it does not have the necessary inventory, which will result in a late core meltdown. Consequently, the probability of failure on demand of low pressure recirculation is equal to one, rather than 4.6E-4 as suggested by Table 4, as long as no special measures are taken by the plant staff, for example using Severe Accident Mitigation Guidelines. Emergency actions that could take place include providing additional borated water to the refueling water storage tank or the containment sump.
Figure 4. SLB-induced SGTR event tree developed using SAPHIRE [20]
Chapter 3: Main Steam Isolation Valve

The purpose of Chapter 3 is to analyze the role of the MSIV in the accident scenario (Section 3.1) and provide background on MSIV failures (Section 3.2). This information is used in conjunction with knowledge about MSIV failure records to assess the probability of MSIV failure per demand (Section 3.2.4).

3.1. The Role of MSIV in Accident Scenario

As described in Chapter 2, the primary accident scenario of interest is initiated by a steam line break outside the containment, followed by a MSIV failure and a rupture of a SG tube. Chapter 3 describes the analysis leading to estimation of MSIV failure. The following information was largely gathered from NUREG/CR-6246 report, titled “Effects on Aging and Service Wear on Main Steam Isolation Valves and Valve Operators” [21].

One of the purposes of a MSIV is to limit the consequences of a steam line break. In PWRs, MSIVs are typically located within a valve vault as depicted in Figure 5. The three types of MSIVs include check, globe, and gate valves (type I and type II), shown in Figure 6, 7, 8, and 9 for a visual reference. A detailed description of each valve and the mechanics involved is provided in NUREG/CR-6246 [21]. Depending on the design of the MSIV, it may only stop flow in the downstream direction, providing protection for the turbine. For those designs, it is necessary to also include a check valve in the line that limits backflow for a break upstream of the valve. During incidents of line breaks inside
of containment, the MSIVs must close within approximately 5 seconds to isolate reverse steam flow from the intact SGs [21]. This allows maintaining the containment pressure within its design limits. The containment is designed to withstand only one SG blowdown. Closure time can affect the rate and extent of SG depressurization and thus affect the likelihood of an induced failure of a SG tube.

Figure 5. Main steam system in a PWR (adapted from [21])
3.2. Main Steam Isolation Valve Failures

3.2.1. Modes of Failure

MSIV failure modes can be divided into six categories: failure to open, failure to close, spurious valve closure, spurious valve open, valve stem or shaft leakage, and valve seat leakage. The distribution of these modes among the three types of valves is shown in Table 5. This information was cited in NUREG/CR-6246 from the Nuclear Plant Reliability Data System (NPRDS) based on the early LWR performance history. In the case of check valves, valve stem or shaft leakage and failure to close modes play the greatest role. Similarly, in globe valves, valve stem or shaft leakage along with failure to close and failure to open are the most prominent failure modes. In the case of the gate valves, failure to open and failure to close seem to be the most significant failure types. The data lists 132 check valve failures and only 58 and 29 failures of the gate and globe valves, respectively. Failure to close of a MSIV is the mode of concern analyzed in the accident scenario. Entries involving this type of failure are highlighted in the following tables for easy reference.
### Table 5. MSIV failure mode distribution (adapted from [21])

<table>
<thead>
<tr>
<th>Mode</th>
<th>Check Valve</th>
<th>Globe Valve</th>
<th>Gate Valve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Failure to open</td>
<td>13%</td>
<td>21%</td>
<td>36%</td>
</tr>
<tr>
<td>Failure to close</td>
<td>30%</td>
<td>24%</td>
<td>26%</td>
</tr>
<tr>
<td>Spurious valve opening</td>
<td>1%</td>
<td>-</td>
<td>5%</td>
</tr>
<tr>
<td>Spurious valve closure</td>
<td>11%</td>
<td>17%</td>
<td>19%</td>
</tr>
<tr>
<td>Valve stem or shaft leakage</td>
<td>30%</td>
<td>31%</td>
<td>12%</td>
</tr>
<tr>
<td>Body-to-bonnet leakage</td>
<td>15%</td>
<td>7%</td>
<td>2%</td>
</tr>
<tr>
<td>Valve-seat leakage</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total Failures</td>
<td>132</td>
<td>29</td>
<td>58</td>
</tr>
</tbody>
</table>

3.2.2. Valve and Actuator Failures

Failures of a MSIV can be attributed to either the valve itself or the valve actuator. Table 6, 7 and 8 show the relative importance of actuator and valve problems associated with each failure mode for check, globe, and gate valves, respectively. It is difficult to identify any strong trends among these failures. However, the data suggest that some failure modes are limited to valve problems only (i.e. valve stem or shaft leakage, body-to-bonnet leakage), while others are primary caused by the actuator (i.e. spurious valve closure or opening).

### Table 6. Check MSIV actuator and valve problems (adapted from [21])

<table>
<thead>
<tr>
<th>Mode</th>
<th>Actuator Problems</th>
<th>Valve Problems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Failure to open</td>
<td>59%</td>
<td>41%</td>
</tr>
<tr>
<td>Failure to close</td>
<td>37%</td>
<td>63%</td>
</tr>
<tr>
<td>Spurious valve opening</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Spurious valve closure</td>
<td>93%</td>
<td>7%</td>
</tr>
<tr>
<td>Valve stem or shaft leakage</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Body-to-bonnet leakage</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Mode</td>
<td>Actuator Problems</td>
<td>Valve Problems</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>-------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>Failure to open</td>
<td>17%</td>
<td>83%</td>
</tr>
<tr>
<td>Failure to close</td>
<td>43%</td>
<td>57%</td>
</tr>
<tr>
<td>Spurious valve opening</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Spurious valve closure</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Valve stem or shaft leakage</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Body-to-bonnet leakage</td>
<td>-</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 7. Globe MSIV actuator and valve problems (adapted from [21])

<table>
<thead>
<tr>
<th>Mode</th>
<th>Actuator Problems</th>
<th>Valve Problems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Failure to open</td>
<td>95%</td>
<td>5%</td>
</tr>
<tr>
<td>Failure to close</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Spurious valve opening</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Spurious valve closure</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Valve stem or shaft leakage</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Body-to-bonnet leakage</td>
<td>-</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 8. Gate MSIV actuator and valve problems (adapted from [21])

3.2.3. Valve and Actuator Failure Mechanisms

According to NUREG/CR-6246, the three mechanisms responsible for failure are valve stem/shaft binding, internal binding, and worn valve packing [21]. The distribution of failures among different mechanisms for each type of valve is shown in Table 9.

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Check Valve</th>
<th>Globe Valve</th>
<th>Gate Valve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valve stem/shaft binding</td>
<td>35%</td>
<td>27%</td>
<td>11%</td>
</tr>
<tr>
<td>Internal binding</td>
<td>16%</td>
<td>13%</td>
<td>11%</td>
</tr>
<tr>
<td>Worn valve packing</td>
<td>49%</td>
<td>60%</td>
<td>78%</td>
</tr>
<tr>
<td>Total Number of Failure Mechanisms</td>
<td>82</td>
<td>15</td>
<td>9</td>
</tr>
</tbody>
</table>

Table 9. Valve failure mechanisms (adapted from [21])
In the case of check valves and globe valves, a worn valve packing is a major cause for valve stem leakage. Valve shaft/stem binding, occurring in all valve types, is a result of excessive friction due to hardening of the valve packing caused by heat, inadequate lubrication of the valve, and over-torqued packing glands. Internal binding occurs in check valves due to disc jamming the valve body, seized shaft bearings, worn internal parts, thermal cycling, and misalignment of internal parts due to aging and maintenance error. In the case of globe valves, internal binding is caused by binding of the yoke rod guides or stanchion guides. In gate valves, internal binding is a result of wedging of the disc in the valve body, which prevents valve movement [21].

Furthermore, valve actuators can be divided into three categories [21]:

- Type A – actuators that use pneumatics to open and springs to close MSIVs (predominantly found on check valves and globe valves)
- Type B – actuators that use hydraulics to open and pneumatics to close MSIVs (predominantly found on gate valves)
- Type C – actuators that use hydraulics both to open and close MSIVs (predominantly found on gate valves)

The failure mode distribution associated with each actuator is shown in Table 10. It appears that Type A actuators suffer mostly from electrical and pneumatic failures, while hydraulic failures appear to be the most common mode found in Type B and Type C actuators.
<table>
<thead>
<tr>
<th>Mode</th>
<th>Type A</th>
<th>Type B</th>
<th>Type C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrical failures</td>
<td>46%</td>
<td>24%</td>
<td>10%</td>
</tr>
<tr>
<td>Pneumatic failures</td>
<td>40%</td>
<td>26%</td>
<td>36%</td>
</tr>
<tr>
<td>Hydraulic failures</td>
<td>2%</td>
<td>50%</td>
<td>53%</td>
</tr>
<tr>
<td>Mechanical failures</td>
<td>12%</td>
<td>-</td>
<td>1%</td>
</tr>
<tr>
<td>Total Number of Failures</td>
<td>115</td>
<td>46</td>
<td>139</td>
</tr>
</tbody>
</table>

Table 10. Actuator failure mode distribution (adapted from [21])

NUREG/CR-6246 cites a total of 183 stressors that affect valves and 331 stressors that affect actuators in PWRs. Table 11 lists some of the more common valve stressors and their relative occurrence. Table 12 provides information on common actuator stressors. The tables suggest that normal aging is the most dominant stressor affecting both PWR valves and actuators.

<table>
<thead>
<tr>
<th>Stressor</th>
<th>Relative occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal aging</td>
<td>39%</td>
</tr>
<tr>
<td>Maintenance errors</td>
<td>29%</td>
</tr>
<tr>
<td>Friction</td>
<td>15%</td>
</tr>
<tr>
<td>Unknown</td>
<td>6%</td>
</tr>
<tr>
<td>High ambient temperature</td>
<td>4%</td>
</tr>
<tr>
<td>Stress corrosion</td>
<td>4%</td>
</tr>
<tr>
<td>Design errors</td>
<td>3%</td>
</tr>
</tbody>
</table>

Table 11. Stressors affecting PWR valves (adapted from [21])
<table>
<thead>
<tr>
<th>Stressor</th>
<th>Relative occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal aging</td>
<td>38%</td>
</tr>
<tr>
<td>Unknown</td>
<td>23%</td>
</tr>
<tr>
<td>Maintenance errors</td>
<td>19%</td>
</tr>
<tr>
<td>Design errors</td>
<td>12%</td>
</tr>
<tr>
<td>Vibration</td>
<td>3%</td>
</tr>
<tr>
<td>High humidity</td>
<td>3%</td>
</tr>
<tr>
<td>High ambient temperature</td>
<td>2%</td>
</tr>
</tbody>
</table>

Table 12. Stressors affecting PWR valve actuators (adapted from [21])

3.2.4. Assessed Probability of Failure

The data reported in NUREG/CR-6246 about MSIV failure rates came from the NPRDS database over a period of nine years, from January 1, 1984 to January 1, 1993. In 80 operating units, 422 BWR and 418 PWR failures were identified. Since PWRs are the focus of this study, it is assumed that 2/3 of the plants are PWRs, i.e. 54 units. Variations of PWR systems include designs with two, three, or four steam generators. This study focuses on a plant with four SGs, and therefore assumes four MSIVs. Based on the North Anna Power Station technical specifications, MSIVs are tested once per every outage, which at the time of writing of those specifications implies once per year. It is assumed that during this period there was a slow closure of the MSIVs at shutdown, a rapid closure of the MSIVs as part of the surveillance test and one inadvertent shutdown. Based on the above data, 27% of failures involved failures to close. With these assumptions, the failure rate per demand is 1.9E-2. This is a substantially larger number than the value of 1E-4 used in the Zion plant SAR. Consequently, the value of 1.9E-2 is used in this analysis. However, a surveillance period of 18 months is assumed to account for the decreased number of plant shutdowns with high burnup fuel.
Figure 6. PWR check valve (adapted from [21])
Figure 7. PWR globe valve (adapted from [21])
Figure 8. PWR Type I gate valve (adapted from [21])
Figure 9. PWR Type II gate valve (adapted from [21])
Chapter 4: Flow-Accelerated Corrosion (FAC) of Steam Line

Chapter 4 introduces the first degradation mechanism considered in this study, the flow-accelerated corrosion of a steam line. The definition, mechanism, and factors influencing the FAC rate are provided in Section 4.1. Section 4.2 contains information on the KWU-KR and load-capacity models used to determine the wall thickness of piping subjected to FAC and its ability to withstand the imposed pressure differential without rupturing.

4.1. Phenomenological Background

4.1.1. Definition

Carbon steel piping of the secondary side carrying flowing water or wet steam is often subjected to FAC. This degradation process leads to wall thinning (material loss) that may result in pipe leaks or rupture. One of the most notable accidents caused by FAC occurred on December 9, 1986 at the Surry Nuclear Power Station. A rupture of an elbow in the condensate system resulted in four fatalities [22]. Historically, FAC has been the most destructive corrosion mechanism for high-energy (100-250°C) carbon steel pipes in LWRs [23]. In PWRs, FAC has been only recorded in piping outside the containment [23]. This type of degradation is of great concern because without proper surveillance it may cause sudden ruptures[22]. Figure 10 and Figure 11 show examples of components
damaged by FAC. Ultrasonic testing is a common method for determining wall thinning of carbon steel pipes caused by FAC.

![Image](image1.png)

**Figure 10.** 18" elbow wall thickness decreases from 12.7 to 1.5 mm on feedwater pump inlet at Surry in 1986 (adapted from [24])

![Image](image2.png)

**Figure 11.** Failure of high pressure extraction line at Fort Calhoun in 1997 (adapted from [24])

4.1.2. Description of Mechanism

Under normal conditions, a thin, protective layer of magnetite (Fe$_3$O$_4$) forms on the inside surface of carbon steel feedwater piping. During a FAC attack, metal oxidation
occurs at the metal-oxide interface in deoxygenated water. Ferrous species (Fe$^{2+}$) dissolve through the porous oxide layer into the main water flow [22, 24]. Then, the magnetite is dissolved at the oxide-water interface. Finally, ferrous irons transfer into the bulk flowing water across the diffusion boundary layer [22, 24]. During this step, the species migrated from the metal-oxide interface and the species dissolved at the oxide-water interface diffuse into the flowing water [22, 24].

FAC occurs in single- and two-phase flows. However, presence of water in its liquid state is necessary, and therefore it does not affect pipelines transporting dry or superheated steam [22]. Single-phase FAC damage can be characterized by overlapping horseshoe pits that give scalloped or orange peel appearance [22, 23]. In pipes damaged by two-phase FAC, the locations affected take on tiger-striped appearance.

4.1.3. Factors Influencing FAC Rate

Studies have shown that hydrodynamics, metallurgy, and environmental factors play an important role in determining the rate of FAC [22-24]. Hydrodynamic variables include pipe geometry, pipe roughness, flow type and flow velocity. FAC occurs downstream of flow-restricting or redirecting geometries that lead to severe changes in flow direction and flow instabilities [24]. Components that contribute to high velocity and turbulent flow tend to experience higher degradation rates. Examples of such components include elbows, tees, reducers, and valves. Consequently, FAC examinations focus on pipe elbows and tee fittings. In addition, components upstream of other components often experience a more turbulent flow and thus a greater FAC rate [24].
Environmental variables pertain mostly to the fluid chemistry and temperature. FAC is dependent on parameters such as pH, impurities, and concentrations of oxygen and ferrous ions [22, 23]. Changes to the metallurgy of the pipe, or its chemical composition, can also impact the rate of FAC. It was found that steels made with chromium content as low as 0.1% will experience low or negligible FAC degradation [22, 24]. Trace amounts of molybdenum and copper in carbon steels can also increase their resistance to FAC [23].

4.2. Predicting Pipe Failure

4.2.1. KWU-KR Model Description

Industry and laboratory experience has led to the development of several empirical models aimed at predicting rates of FAC and resulting pipe ruptures. The three most commonly used codes for modeling FAC are contained within the WATHEC, CHECKWORKS, and BRT-Cicero packages [23]. The use of the latter two, however, is somewhat limited due to their proprietary nature. The KWU-KR model developed by Kastner and Riedle as part of the WATHEC code produced by Siemens/KWU is openly available and has been widely analyzed in published literature [23]. As a result, it has been selected for FAC analysis performed as part of the scenario of concern analyzed in this thesis.

The details of the model listed in this section are solely based on the model description provided in NUREG/CR-5632 and listed as [23]. NUREG/CR-5632 is a report prepared
by INL aimed at incorporating aging effects into PRA. The report emphasizes FAC as a failure mode in attempt to show the feasibility of utilizing reliability physics models in PRA and associated aleatory and epistemic uncertainties [23]. Although the work performed as part of NUREG/CR-5632 is similar to the study presented in this thesis on the surface, the main difference can be seen in the methodology used. NUREG/CR-5632 assigns distributions to the variables in the KWU-KR and load-capacity models. This treatment allowed the authors of that report to develop a probability of failure at any given time of plant operation and consequently translate that in terms of plant risk. On the other hand, the study described in this thesis develops a state-dependent PRA model (Chapter 6), which considers effectiveness of surveillance and allows for adjustments related to component rejuvenation. In addition, this research considers two simultaneously acting corrosion mechanisms in two locations of the plant. The FAC affecting the secondary power conversion piping induces a rupture of SG tubes that are already degraded by SCC. In comparison, NUREG-5632 only analyzed FAC as an initiating event and did not consider its impact on other components (i.e. SG tubes).

The KWU-KR model determines the rate of wall thinning due to flow-accelerated corrosion. This approach accounts for Keller’s geometric factor, flow velocity, chemistry and temperature, piping metallurgy, and exposure time [23]. The model can be also adjusted to analyze two-phase flow. Accordingly, the specific rate of FAC is expressed in Eq. (1).
\[ \Delta \phi_{R,KWU-KR} = 6.35k_c(\text{Be}^{Nw}[1 - 0.175 \cdot (\text{pH} - 7)^2] \cdot 1.8e^{-0.118g} + 1) \cdot f(t) \]  

\( B = -10.5\sqrt{h} - 9.375 \times 10^{-4} \cdot T^2 + 0.79T - 132.5 \)

\( N = -0.0875h - 1.275 \times 10^{-5} \cdot T^2 + 1.078 \times 10^{-2} \cdot T - 2.15 \)  
(for 0% ≤ h ≤ 0.5%)

\( N = (-1.29 \times 10^{-4} \cdot T^2 + 0.109T - 22.07) \cdot 0.154 \cdot e^{1.2h} \)  
(for 0.5% ≤ h ≤ 5%)

where

\( \Delta \phi_{R,KWU-KR} = \text{specific FAC rate (\(\mu\text{g}/(\text{cm}^2\text{h})\))} \)

\( k_c = \text{Keller's geometry factor} \)

\( w = \text{flow velocity (m/s)} \)

\( \text{pH} = \text{pH value} \)

\( g = \text{oxygen content (ppb)} \)

\( h = \text{content of chromium and molybdenum in steel (total %)} \)

\( T = \text{temperature (K)} \)

\( f(t) = \text{time correction factor} \)

In case of a two phase flow, the flow velocity, \( w \), in Eq. (1) is modified according to Eq. (2).

\[ w_F = \frac{\dot{m}}{\rho_w} \frac{1 - x_{st}}{1 - \alpha} \]  

where

\( w_F = \text{mean velocity in the water film on the inside surface (m/s)} \)

\( \dot{m} = \text{mass flux (kg/(m}^2\text{s}))) \)
\[ \rho_w = \text{density of the water at saturation condition (kg/m}^3) \]

\[ x_{st} = \text{steam quality} \]

\[ \alpha = \text{void fraction} \]

The time correction factor, \( f(t) \), in Eq. (1) is determined using Eq. (3) below. For short operating periods, the time factor approaches unity.

\[ f(t) = C_1 + C_2 t + C_3 t^2 + C_4 t^3 \quad (3) \]

where

\[ f(t) = \text{time correction factor} \]

\[ t = \text{exposure time (hr)} \]

\[ C_1 = 9.999934 \times 10^{-1} \]

\[ C_2 = -3.356901 \times 10^{-7} \]

\[ C_3 = -5.624812 \times 10^{-11} \]

\[ C_4 = 3.849972 \times 10^{-16} \]

Specific pipe geometries and associated geometric factors, \( k_c \), in Eq. (1) are shown in Table 13.
<table>
<thead>
<tr>
<th>Pipe Geometry</th>
<th>Keller’s Geometric Factor, $k_c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Straight tube</td>
<td>0.04</td>
</tr>
<tr>
<td>Leaky joints, labyrinths</td>
<td>0.08</td>
</tr>
<tr>
<td>Behind junctions</td>
<td>0.15</td>
</tr>
<tr>
<td>Behind tube inlet (sharp edge)</td>
<td>0.16</td>
</tr>
<tr>
<td>Elbow, R/D = 2.5</td>
<td>0.23</td>
</tr>
<tr>
<td>Elbow, R/D = 1.5</td>
<td>0.30</td>
</tr>
<tr>
<td>In and over blades</td>
<td>0.30</td>
</tr>
<tr>
<td>Elbow, R/D = 0.5</td>
<td>0.52</td>
</tr>
<tr>
<td>In branches #2</td>
<td>0.60</td>
</tr>
<tr>
<td>In branches #1</td>
<td>0.75</td>
</tr>
<tr>
<td>On tubes, on blade, or on plate</td>
<td>1.00</td>
</tr>
</tbody>
</table>

**Table 13. Keller’s geometric factor, $k_c$, in Eq. (1) (adapted from [23])**

Equation (1) combined with information about the pipe’s material and exposure time is used to calculate wall corrosion, $h_c$, as shown in Eq. (4).

$$h_c(t) = \frac{\Delta \phi_R t}{\rho_{st}}$$

where

- $h_c(t)$ = calculated thickness of pipe corroded away at time $t$ (cm)
- $\Delta \phi_R$ = specific FAC rate ($\mu g/(cm^2 \cdot h)$)
- $t$ = exposure time (hr)
- $\rho_{st}$ = density of steel ($\mu g/cm^3$)

Given the original wall thickness and the corrosion rate, the wall thickness as a function of time is determined using Eq. (5).
\[ h_{\text{pipe}}(t) = h_{\text{original}} - h_c(t) \]  

where

\[ h_{\text{pipe}}(t) = \text{pipe wall thickness at time } t \text{ (cm)} \]
\[ h_{\text{original}} = \text{nominal pipe wall thickness (cm)} \]
\[ h_c(t) = \text{calculated thickness of pipe corroded away at time } t \text{ (cm)} \]

4.2.2. Assumptions and Regions of Validity

The model developed by Kastner and Riedle is based on a number of assumptions [23]. First, the model is valid for operating periods beyond 200 hours. However, high rates of material losses can occur during plant start-up. Material losses are assumed negligible at water temperatures above 240°C. Second, although studies have shown material resistance to FAC in carbon steel piping containing at least 0.1% chromium, the model allows for a maximum chromium and molybdenum content of 0.5%. The protective magnetite layer dissolves in deoxygenated water. Therefore, the model assumes oxygen content below 30 ppb. Higher concentrations result in constant and negligible FAC rates. Furthermore, plant data suggests very small FAC rates for concentrations beyond 15 ppb. In addition, water pH levels in PWRs fall in the range from 8.5 to 9.5. Third, the model assumes a constant corrosion rate of 1 μg/cm²h for pH level above 9.39. However, it has been shown that in reality FAC rates continue to increase with increasing pH values beyond this limit. Finally, the model is only valid up until the critical velocity, after which material removal occurs by a mechanical process.
4.2.3. Load-Capacity Formulation

Failure of a component damaged by FAC can be calculated using a load-capacity formulation. In the case of feedwater carbon steel piping, the load is defined as pressure imposed on the piping during steady-state and transient conditions. The capacity is defined as the maximum pressure sustainable by a pipe subjected to wall thinning. A pipe fails when the load exceeds the capacity. NUREG/CR-5632 uses capacity expression from Wesley et al. shown in Eq. (6) [23]. It is assumed that the wall thinning is uniform around the circumference of the pipe and that the equation is valid for non-straight segments such as elbows [23]. Although this assumption deviates from the actual wall thinning behavior observed in non-straight segments subjected to FAC, the specific FAC rate equation, shown in Eq. (1), corrects for that through the Keller’s geometry factor, $k_c$.

\[ p_{\text{capacity}}(t) = \frac{\sigma_f \cdot h_{\text{pipe}}(t)}{[r + h_c(t)](1 + 0.25\varepsilon_f)} \]  

(6)

where

$P_{\text{capacity}}(t) =$ pressure capacity at time $t$ (ksi)

$\sigma_f =$ failure stress (ksi)

$r =$ nominal pipe radius (cm)

$h_{\text{pipe}}(t) =$ pipe wall thickness at time $t$ (cm)

$h_c(t) =$ calculated thickness of pipe corroded away at time $t$ (cm)

$\varepsilon_f =$ median hoop strain at failure
4.2.4. Example Applications from Literature

Two industry examples of FAC-caused failures were tested to determine the accuracy of the KWU-KR model and the load-capacity formulation [23]. The first of these is a failure of an elbow downstream of a tee that occurred in Surry Unit 2 on December 9, 1986. The second example is based on the failure of a heat drain pump discharge piping that occurred at the Trojan Station on March 9, 1985. The plant data used in the analysis is shown in Table 14. The results for the accidents at Surry and Trojan are shown in Figure 12 and Figure 13, respectively. The predicted times of failure at Surry and Trojan are 9.4 and 13.5 years, respectively. The elbow at Surry Unit 2 failed after 13.4 years of operation and the heat drain pump discharge piping at Trojan failed after 8.71 years. However, much of the difference between the actual and predicted failures can be explained by the uncertainty in the parameters used in the analysis [23]. Some of the variables pertaining to these accidents were difficult to estimate and assumptions about them had to be made. Nevertheless, the time of failure predicted by the model does provide a realistic insight into the nature of the problem and can serve as a reasonable basis for estimating the likelihood of damage [23].
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Surry Unit 2</th>
<th>Trojan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
<td>Elbow downstream of a tee</td>
<td>Heat drain pump discharge piping</td>
</tr>
<tr>
<td>Actual time of failure</td>
<td>117,360 hr (13.4 yrs)</td>
<td>76,320 hr (8.71 yrs)</td>
</tr>
<tr>
<td>Chromium and molybdenum content</td>
<td>0.08%</td>
<td>0.08%</td>
</tr>
<tr>
<td>Geometric factor</td>
<td>0.75</td>
<td>0.23</td>
</tr>
<tr>
<td>Flow velocity</td>
<td>5.18 m/s</td>
<td>9.91 m/s</td>
</tr>
<tr>
<td>Oxygen content</td>
<td>1.2 ppb</td>
<td>1.2 ppb</td>
</tr>
<tr>
<td>Water chemistry</td>
<td>8.9 pH</td>
<td>8.9 pH</td>
</tr>
<tr>
<td>Water temperature</td>
<td>463 K</td>
<td>463 K</td>
</tr>
<tr>
<td>Steam quality</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Carbon steel density</td>
<td>$8.5 \times 10^6$ μg/cm$^3$</td>
<td>$8.0 \times 10^6$ μg/cm$^3$</td>
</tr>
<tr>
<td>Strength</td>
<td>420.6 MPa (61 ksi)</td>
<td>517.1 MPa (75 ksi)</td>
</tr>
<tr>
<td>Failure strain</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td>Component diameter</td>
<td>45.7 cm</td>
<td>10.16 cm</td>
</tr>
<tr>
<td>Component thickness</td>
<td>1.27 cm</td>
<td>0.856 cm</td>
</tr>
<tr>
<td>Load</td>
<td>2.55 MPa</td>
<td>3.10 MPa</td>
</tr>
</tbody>
</table>

Table 14: Parameters used to simulate actual FAC degradations (adapted from [23])

![Figure 12. Failure of an elbow downstream of a tee at Surry Unit 2](image-url)
Figure 13. Failure of a heat drain pump discharge piping at Trojan
Chapter 5: Stress Corrosion Cracking (SCC) in the Steam Generator Tubes

The purpose of Chapter 5 is to introduce the second degradation mechanism considered in this study, the stress corrosion cracking in the steam generator tubes. Section 5.1 provides background on steam generators. Section 5.2 explains primary water stress corrosion cracking and its impact on materials used in manufacturing steam generators. Section 5.3 provides information on SCC growth models in SG tubes.

5.1. Steam Generator

5.1.1. Purpose and Designs

A unique feature of PWRs is the separation of the cycle into two loops as shown in Figure 14. The coolant within the primary loop carries the heat from the reactor core to the steam generator. In the secondary loop, the SG produces steam, which drives the turbine generator. From a physical perspective, SGs are very large components, measuring up to 70 ft. in height and weighing as much as 800 tons [25]. Inside of the SGs are located thousands of feet of tubing. Depending on its design a SG typically contains anywhere from 3,000 to 16,000 tubes [25]. The primary loop water enters the SG through a hot leg. This water is delivered at high temperature and at pressure greater than the saturation pressure to prevent boiling. The primary water flowing through the inside of the SG tubes heats the secondary water on the outside of the tubes and converts it into
steam. The primary water exits the SG through the cold leg at a much lower temperature and is pumped back into the reactor core. Thus, the SG is essentially a heat exchanger that transfers heat between the two loops of the steam cycle.

![Diagram](image)

**Figure 14. Westinghouse-designed two-loop PWR steam cycle (adapted from [26])**

Nuclear power plants in the United States use two types of steam generators: once-through generators created (OTSG) by Babcock & Wilcox Company (B&W) and Westinghouse-designed and Combustion Engineering-designed recirculating steam generators (RSGs). Cutaway views of both types are shown in Figure 15.
An OTSG consists of straight tubes with tube sheets at the top and bottom of the SG. Primary water is pumped through the tubes from top to bottom, while secondary water is fed around the outside of the tubes from bottom to top in the opposite direction. The superheated steam is directly generated as the feedwater flows through the OTSG in a single pass [28, 29].

Inside of a RSG is a bundle of inverted U-tubes. Primary water enters through the hot leg, flows through these U-tubes and exists though a cold leg. The secondary loop water is fed to the RSG through a feedwater nozzle and into the downcomer. The
downcomer water flows to the bottom of the RSG, across the top of the tube sheet, and then up through the tube bundle where steam is generated. A steam/moisture separator is located near the top of a RSG. The moisture is recirculated back to the downcomer, while steam exists the RSG. Only about 25% of the secondary water is converted to steam during each pass [29].

Most PWRs in the U.S. use recirculating steam generators [30]. The Zion Nuclear Power Station, model plant for this research, used a Westinghouse RSG. Several Westinghouse RSG models have a tube outside diameter (OD) of 22.23 mm and a wall thickness of 1.27 mm [29]. In addition, the primary loop pressure in a RSG is typically 15.5 MPa, while the secondary pressure is around 5.7 MPa. The hot leg temperature in RSGs ranges from 315°C to 330°C, while cold leg temperature is usually 288°C [29].

5.1.2. Material Considerations

The integrity of the SG is essential since a leak of a sufficient size or a rupture may contaminate the steam in the secondary loop and cause a release of radioactive material to the environment. To meet this challenge, special materials and heat treatments are used for the construction of SGs [25]. Many of the primary circuit components such as reactor pressure vessel (RPV), pressurizer, or the steam generator are produced from nickel-based alloys (referred by their trademark name as Inconels). These alloys have coefficients of thermal expansion similar to low alloy steels and are characterized by relatively high corrosion resistance in PWR primary and secondary water environments [30]. The use of nickel-based alloys has evolved over the decades as new degradation
mechanisms were almost immediately observed. Table 15 summarizes some of the common degradation mechanisms found in SGs. In addition, Figure 16 shows the contribution of major degradation mechanisms to the tube plugging in recent years.

<table>
<thead>
<tr>
<th>Type of Degradation</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denting</td>
<td>Mechanical deformation of tubes near the support plate caused by buildup of corrosive material between the tube and its support plate</td>
</tr>
<tr>
<td>Fretting</td>
<td>Wearing of tubes in their supports due to flow-induced vibration</td>
</tr>
<tr>
<td>Outside Diameter SCC (ODSCC)</td>
<td>Corrosion on the outside of SG tubes exposed to secondary water mostly occurring in the tube sheet and support plate crevices</td>
</tr>
<tr>
<td>Intergranular Attack (IGA)</td>
<td></td>
</tr>
<tr>
<td>Pitting</td>
<td>Small-diameter wall penetrations resulting from local corrosion cells, probably promoted by the presence of chloride and sulfate acids</td>
</tr>
<tr>
<td>PWSCC</td>
<td>Stress corrosion cracking occurring at the inner surface of tubes exposed to primary water</td>
</tr>
<tr>
<td>Wastage</td>
<td>Corrosion of tubes caused by chemical attack from phosphate residues in areas of low water flow</td>
</tr>
<tr>
<td>Fatigue</td>
<td>Caused by tube vibration</td>
</tr>
</tbody>
</table>

Table 15. Common degradation mechanisms found in steam generators ([27, 29])
In the early-to-mid 1970s, all NPPs in the United States, except for one, used SGs made from mill-annealed Alloy 600 (600MA). However, the water chemistry caused excessive thinning. In response, NPPs changed their water control programs to eliminate this mechanism [25]. In the mid-to-late 1970s, denting resulting from the corrosion of the carbon steel support plates and the buildup of corrosion product in the crevices between tubes and tube support plates became a major issue. Although measures such as changes in the chemistry of secondary loop were taken to limit this problem, other mechanisms continued to cause cracking in plants with Alloy 600MA tubes [25]. The excessive issues with Alloy 600MA SGs forced the industry to replace them with SGs made from high-temperature treated Alloy 600 (600TT). The replacement process began in the early 1980s and up until now no significant degradation issues have been observed. Nevertheless, beginning in 1989, NPPs began using SGs made from thermally treated...
Alloy 690, which is believed to be even more corrosion resistant due to its nearly doubled chromium content. The switch to Alloy 690 was accompanied by changes in corresponding weld metals. Alloys 152 and 52 replaced previously used weld Alloys 182 and 82. The chemical composition of these alloys is shown in Table 16.

<table>
<thead>
<tr>
<th></th>
<th>Alloy 600</th>
<th>Alloy 182</th>
<th>Alloy 82</th>
<th>Alloy 690</th>
<th>Alloy 152</th>
<th>Alloy 52</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ni</td>
<td>&gt;72.0</td>
<td>Bal.</td>
<td>Bal.</td>
<td>&gt;58.0</td>
<td>Bal.</td>
<td>Bal.</td>
</tr>
<tr>
<td>Cr</td>
<td>14-17</td>
<td>13-17</td>
<td>18-22</td>
<td>28-31</td>
<td>28-31.5</td>
<td>28-31.5</td>
</tr>
<tr>
<td>Fe</td>
<td>6-10</td>
<td>≤10</td>
<td>≤3</td>
<td>7-11</td>
<td>8-12</td>
<td>8-12</td>
</tr>
<tr>
<td>Ti</td>
<td>-</td>
<td>≤1</td>
<td>≤0.75</td>
<td>-</td>
<td>≤0.50</td>
<td>≤1.0</td>
</tr>
<tr>
<td>Al</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>≤1.10</td>
</tr>
<tr>
<td>Nb plus Ta</td>
<td>-</td>
<td>1.0-2.5</td>
<td>2.0-3.0</td>
<td>-</td>
<td>1.2-2.2</td>
<td>≤0.10</td>
</tr>
<tr>
<td>Mo</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>≤0.50</td>
<td>≤0.05</td>
</tr>
<tr>
<td>C</td>
<td>≤0.05</td>
<td>≤0.10</td>
<td>≤0.10</td>
<td>≤0.04</td>
<td>≤0.045</td>
<td>≤0.040</td>
</tr>
<tr>
<td>Mn</td>
<td>≤1.0</td>
<td>5.0-9.5</td>
<td>2.5-3.5</td>
<td>≤0.50</td>
<td>≤5.0</td>
<td>≤1.0</td>
</tr>
<tr>
<td>S</td>
<td>≤0.015</td>
<td>≤0.015</td>
<td>≤0.015</td>
<td>≤0.015</td>
<td>≤0.008</td>
<td>≤0.008</td>
</tr>
<tr>
<td>P</td>
<td>-</td>
<td>≤0.030</td>
<td>≤0.030</td>
<td>≤0.030</td>
<td>≤0.020</td>
<td>≤0.020</td>
</tr>
<tr>
<td>Si</td>
<td>≤0.5</td>
<td>≤1.0</td>
<td>≤0.50</td>
<td>≤0.50</td>
<td>≤0.65</td>
<td>≤0.50</td>
</tr>
<tr>
<td>Cu</td>
<td>≤0.5</td>
<td>≤0.50</td>
<td>≤0.50</td>
<td>≤0.5</td>
<td>≤0.50</td>
<td>≤0.30</td>
</tr>
<tr>
<td>Co</td>
<td>≤0.10</td>
<td>≤0.12</td>
<td>≤0.10</td>
<td>≤0.10</td>
<td>≤0.020</td>
<td>≤0.020</td>
</tr>
</tbody>
</table>

Table 16. Percent composition of Alloys 600, 690 and corresponding weld alloys (adapted from [30])

5.1.3. Remedial Measures

Plugging is one of the most common repair methods for SG tubing. In the past, plugs were made from bar stock of Alloy 600. However, since plugged tubes continue to be susceptible to SCC, fatigue, and fretting, current plugs are produced from Alloy 690 [29]. Common plugging techniques include welding, explosive forming and mechanical installation [29]. A major disadvantage of plugging is the loss of SG heat transfer...
efficiency. SGs with 15-20% of their tubes plugged require derating or replacement [26]. Excessive plugging hinders coolant flow and may lead to power reduction [26]. Plugging is usually the first mean of responding to damaged tubes and SGs are designed to have excess number of tubes. In some SGs, tubes especially susceptible to degradation are plugged upon SG installation.

A common, but more expensive, alternative to plugging is sleeving. However, this method is only applicable to tubes with cracks that do not exceed 40% of tube wall thickness [26]. Tubes suffering from larger crack penetration must be plugged. Sleeves are placed inside PWR SG tubes to bridge the damaged tube regions [29]. They are produced using material more resistant to corrosion than the original tube material. Therefore, most sleeves are made from Alloy 600TT or Alloy 690 [29]. They serve to replace a section of the tube and withstand the loads placed on the original tubing. In addition, sleeves can be used in place of successfully removed plugs. This is sometimes done to restore the SG capacity.

5.2. Primary Water Stress Corrosion Cracking (PWSCC)

5.2.1. Definition of SCC and Necessary Conditions

Stress corrosion cracking is a degradation process in which cracks initiate and propagate to critical sizes in susceptible alloys exposed to tensile stresses and corrosive environment. The three necessary conditions required for SCC are shown in Figure 17. A material must be simultaneously subjected to the combination of these conditions
(susceptible material, corrosive environment, and tensile stresses) for SCC to occur. A reduction in any one of these conditions below a certain threshold may prevent SCC [32]. In addition, the exact conditions of this mechanism are not uniform across all metal alloys. For instance, tensile stresses that cause SCC in one material may not be sufficient to initiate cracking in another material.

Stress corrosion cracking can have either transgranular (TGSCC) or intergranular (IGSCC) morphology. TGSCC occurs through the material grains, whereas IGSCC affects the material along the grain boundaries. Mixed modes of SCC and switching between these modes can be observed in susceptible materials [32].

Analyses of stress corrosion cracking in literature typically divide this mechanism into the initiation phase and propagation phase. During SCC initiation, a crack forms on an apparently smooth surface. The initiation phase varies across materials, operating conditions, and environments and can take even decades to finalize [32]. The mechanisms responsible for crack initiation remain largely unknown. Furthermore, prediction of crack initiation is typically performed using reliability-based statistical methods such as the Weibull distribution or the lognormal distribution. The propagation phase describes the time during which an existing crack grows and in the case of SGs develops from a surface to a through-wall (TW) crack and eventually leads to rupture. Propagation can be divided further into its earlier phase (slow propagation) and its later phase (fast propagation). Crack growth rate (CGR) is a non-linear process and accelerates over time.
The exact phenomenological causes of SCC are still unknown and no well-established theory exists that would allow predicting occurrences of this degradation mechanism. Current methods involve empirical and statistical measures in determining the occurrences of SCC and its growth. SCC is especially of concern because materials affected by SCC often do not manifest any abnormal mechanical properties. Therefore, failures caused by SCC may be sudden, costly and even catastrophic.

![Diagram](image)

**Figure 17. Conditions required for SCC (adapted from [32])**

5.2.2. SCC in Alloy 600 Recirculating Steam Generators

IGSCC and IGA are the most commonly occurring degradation mechanisms in the U.S. steam generators [31, 33]. Intergranular attack is a degradation mechanism in which corrosion attacks along the grain boundaries and the bulk of the grains are
unaffected. The IGSCC occurring on the primary side of steam tubes became known in literature as PWSCC. The secondary side of the steam tubes suffers from both, IGSCC and IGA. Figure 16 shows that stress corrosion cracking and intergranular attack are the major mechanisms causing majority of tube plugging in recent years.

To some extent, PWSCC has been mitigated by replacing older steam generators made with Alloy 600MA by steam generators made with Alloy 690. Laboratory tests and about 16 years of industry service of Alloy 690 SGs have shown that Alloy 690 and its weld metals, Alloys 152 and 52, have proved so far to be resistant to PWSCC [25, 30]. As of 2009, 10 (14%) plants in the U.S. had SGs with Alloy 600MA tubes, 17 (25%) had SGs with Alloy 600TT tubes, and 42 (61%) had SGs with Alloy 690 tubes [25].

PWSCC has been primarily discovered in Westinghouse-type recirculating steam generators [30, 33]. Once-through steam generators are believed to be resistant to PWSCC because they are subjected to a pre-service stress relief process at a temperature of about 610°C (1130°F) [30]. The treatment leads to precipitation of carbides and depletion of chromium content (sensitization) in the grain boundaries. However, in these OTSGs the decreased strength and increased carbon carbides have shown to decrease PWSCC susceptibility, despite sensitization [30].

5.2.3. Regions of Interest

Instances of PWSCC in Alloy 600 tubes have been observed in the roll transition zone (RTZ), U-bends, and denting locations [31, 33]. Figure 18 shows a steam generator tube for a visual reference.
The most common location for PWSCC is the roll transition zone, depicted in Figure 19, consisting of a region of a tube that is slightly expanded and joined to the plate tube sheet [33]. Most of the cracks found in the RTZ were axial, but radial cracks have been also discovered at few plants [31]. The cracks have been found in areas of most severe geometry change experiencing high tensile stresses [31].

The U-bends of tubes are subjected to high residual stresses created during the forming process. The greatest stress levels occur in the inner-row tubes with the smallest radius of curvature [33]. The cracks occur in the irregular region, between the tube flank and the extrados [33]. The irregular region is the section of the tube marking the transition from a straight portion to a U-bend. Cracks found in the U-bends were parallel to the tube axis and caused slowly increasing leakages [31]. Sudden ruptures due to SCC in this region have not been reported.

Both axial and radial cracks have been also reported around the dents at the support plates. However, these have been largely mitigated by improved control of secondary water chemistry and corrosion-resistant tube support plates [31].
Figure 18. Locations of a U-bend tube (adapted from [33])

Figure 19. Roll transition zone (adapted from [34])
5.3. PWSCC Crack Growth Rate Model for Alloy 600MA

5.3.1. Empirical Model

Instances of SCC in operating plants and laboratory tests resulted in research efforts aimed at predicting occurrences of SG failures. One approach towards determining tube failure is to analyze the CGR caused by SCC and the resulting leakage and/or rupture. Several models ranging from probabilistic to deterministic have been developed over the years. The probabilistic models commonly implement Weibull distribution, fitted to industry service data, to determine the likelihood of component failure caused by PWSCC. The deterministic models tend to differ from each other based on the selected mechanism used to explain PWSCC. However, as there is no agreement on the causes of exact phenomenology behind SCC, early studies into PWSCC, focused on the crack propagation regime, led to an empirical CGR equation dependent on the stress intensity factor around the crack tip. This relationship is expressed in Eq. (7). Equation (8) shows that the stress intensity factor is a function of the crack length, stress at crack tip, and crack geometry. Since the length of the crack increases over time, it can be also seen that the stress intensity factor is implicitly dependent on time. By inserting Eq. (8) into Eq. (7), one can see that the CGR equation is actually a first order differential equation that can be solved numerically. Parameter $F$ of Eq. (8) can be estimated based on the crack geometry.
\[
\frac{da}{dt} = \alpha \cdot (K - K_{th})^\beta \\
K = F \sigma \sqrt{\pi a}
\]

where

\( \frac{da}{dt} \) = crack growth rate
\( \alpha \) = crack growth amplitude
\( K \) = crack tip stress intensity factor
\( K_{th} \) = crack tip stress intensity factor threshold
\( \beta \) = exponent
\( F \) = geometric factor
\( \sigma \) = stress at crack tip
\( a \) = crack dimension in the direction of crack growth

5.3.2. Scott CGR Model [35]

Peter Scott refined the general CGR model into the form shown in Eq. (9) for primary water at 330°C using data collected for Alloy 600 by Smialowska et al. [35]. His investigation established the threshold stress intensity factor as 9 MPa√m and the growth exponent as 1.16. The data provided by Smialowska et al., however, was based on a specimen that was machined from a flattened half of a short length of SG tubing [35]. Equation (9) for tubes operating in temperatures of 320°C must be divided by five and those operating in 310°C by ten [35]. In addition, the modified Scott model for non-cold worked Alloy 600 at 330°C is shown in Eq. (10).
\[
\frac{da}{dt} = 2.8 \cdot 10^{-11} \cdot (K - 9)^{1.16} \quad \text{for cold worked Alloy 600} \quad (9)
\]

\[
\frac{da}{dt} = 2.8 \cdot 10^{-12} \cdot (K - 9)^{1.16} \quad \text{for non-cold worked Alloy 600} \quad (10)
\]

where

\[
\frac{da}{dt} = \text{crack growth rate (m/s)}
\]

\[K = \text{crack tip stress intensity factor (MPa}\sqrt{m})\]

The Scott model was initially formed to determine longitudinal (axial) TW crack propagation in Alloy 600 in PWR SG tubes in the roll transition region between the top of the tube sheet and the tube free span above the tube sheet. However, this model has been also used outside its initial assumptions including a simulation on surface crack growth on the inside of SG tubes [36].

5.3.3. MRP CGR Model

The Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) developed a CGR model, shown in Eq. (11), for thick-walled Alloy 600 components using Scott’s findings as its basis [37]. EPRI MRP adjusted crack growth amplitude and accounted for temperature dependence using Arrhenius relationship in its model. EPRI MRP compared CGR curves obtained using modified Scott equation and EPRI MRP equation and showed that the two models are in close agreement. Modified Scott curve indicated lower crack growth rates by about 16% [37].
\[
\frac{da}{dt} = \alpha \cdot \exp \left[-\frac{Q}{R} \cdot \left(\frac{1}{T} - \frac{1}{T_{\text{ref}}}\right)\right] \cdot (K - K_{\text{th}})^\beta
\]  

(11)

where

\( \frac{da}{dt} \) = crack growth rate at temperature \( T \) (m/s)

\( \alpha \) = crack growth amplitude \( (2.67 \times 10^{-12} \text{ at } 325^\circ\text{C}) \)

\( Q \) = thermal activation energy for crack growth \( (130 \text{ kJ/mole}) \)

\( R \) = universal gas constant \( (8.314 \times 10^{-3} \text{ kJ/mole} \cdot \text{K}) \)

\( T \) = absolute operating temperature at location of crack (K)

\( T_{\text{ref}} \) = reference temperature \( (598.15 \text{ K}) \)

\( K \) = crack tip stress intensity factor \( (\text{MPa}\sqrt{\text{m}}) \)

\( K_{\text{th}} \) = crack tip stress intensity factor threshold \( (9 \text{ MPa} \sqrt{\text{m}}) \)

\( \beta \) = exponent \( (1.16) \)
Chapter 6: State-dependent Risk Model and Analysis of Results

Chapter 6 serves to explain the state-dependent risk model and present the results stemming from the selected degradation mechanisms and the hypothetical accident scenario. Section 6.1 is a listing of model assumptions related to PWSCC crack evolution. Section 6.2 fully describes the state-dependent risk model developed as part of this study. Section 6.3 provides results based on the risk model and the model assumptions.

6.1. Model Assumptions

6.1.1. Initial Conditions

The risk model employed in this analysis is based on assumptions, shown in Table 17, concerning the tube material, geometry, operating conditions, and crack morphology. The assumptions were made based on common knowledge related to operating PWRs and Westinghouse-designed RSGs. The analysis focuses on axial growth of a semielliptical crack in the RTZ, because it is one of the most susceptible areas to PWSCC as discussed in Chapter 5. An axial crack growth in a SG tube is shown in Figure 20. In addition, Figure 21 shows another view of an axial crack with labeled dimensions. It is assumed that the crack depth-to-length ratio is constant during crack growth. The rate of crack depth growth is equal to 1/3 of the crack length growth.
<table>
<thead>
<tr>
<th>Material Parameters</th>
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<tr>
<td>Material</td>
<td>Alloy 600MA</td>
</tr>
<tr>
<td>Ultimate tensile strength (UTS), $\sigma_U$</td>
<td>713 MPa [34]</td>
</tr>
<tr>
<td>Yield strength (YS), $\sigma_Y$</td>
<td>362 MPa [34]</td>
</tr>
<tr>
<td>Flow stress, $\sigma_F$</td>
<td>$645$ MPa $[0.6 \times (\sigma_Y + \sigma_U)]$</td>
</tr>
<tr>
<td>Young’s modulus of elasticity, $E$</td>
<td>$200$ GPa [38]</td>
</tr>
<tr>
<td>Poisson ratio, $\nu$</td>
<td>0.31</td>
</tr>
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</table>

<table>
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<tr>
<th>SG/Tube Parameters</th>
<th></th>
</tr>
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<tr>
<td>Tube outside diameter</td>
<td>22.23 mm [29]</td>
</tr>
<tr>
<td>Tube thickness</td>
<td>1.27 mm [29]</td>
</tr>
<tr>
<td>Number of tubes per SG</td>
<td>3592</td>
</tr>
<tr>
<td>Number of SGs</td>
<td>4</td>
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<table>
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<td>Primary side pressure</td>
<td>17.13 MPa</td>
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<tr>
<td>Secondary side pressure</td>
<td>7.48 MPa</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Crack Morphology</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Type</td>
<td>Axial</td>
</tr>
<tr>
<td>Location</td>
<td>Roll transition zone</td>
</tr>
<tr>
<td>Depth-to-length ratio</td>
<td>1:3</td>
</tr>
<tr>
<td>Initial crack length</td>
<td>0.1 mm</td>
</tr>
</tbody>
</table>

**Table 17.** Assumptions about tube materials, geometry, operating conditions, and crack morphology

**Figure 20.** Section view of axial crack growth on the inner surface of a SG tube
6.1.2. Stress Considerations

SG tubes experience stresses due to the pressure and temperature differentials between the primary and secondary sides and residual stresses imposed during tube formation and subsequent treatment. Their dimensions allow them to be modeled as internally pressurized thin-walled cylinders. The pressure differential across a tube wall leads to hoop (circumferential) and axial (longitudinal) stresses according to Eqs. (12) and (13). The hoop stress is the load of interest in the case of axial crack growth and is calculated using the information on tube geometry and operating conditions contained in Table 17 and Eq. (12) to be 11.55 ksi (79.64 MPa).
The thermal and residual stresses are difficult to estimate using traditional strength of materials theories and are typically modeled using finite element analysis (FEA). Shah et al. provide a thorough discussion of stresses present in SG tubes and their causes [33]. Table 18 lists estimated stress levels that are used as a reference for this study. More specifically, the highlighted entry provides the basis for estimating residual and thermal stresses. The hot region of the tube in the RTZ is a more likely location for corrosion than the cold region because of increased susceptibility to PWSCC caused by higher temperatures. Therefore, the total hoop stress resulting from a combination of thermal, residual stresses from Table 18 and operating stress calculated using Eq. (12) is determined to be 79.55 ksi (548.50 MPa).

\[
\sigma_{\text{hoop}} = \frac{p \cdot d}{2t} \quad (12)
\]

\[
\sigma_{\text{axial}} = \frac{p \cdot d}{4t} \quad (13)
\]

where

\( \sigma_{\text{hoop}} = \) hoop stress (MPa)

\( \sigma_{\text{axial}} = \) axial stress (MPa)

\( p = \) pressure differential (MPa)

\( d = \) mean tube diameter (mm)

\( t = \) tube thickness (mm)
<table>
<thead>
<tr>
<th>Location</th>
<th>Pressure axial/hoop (ksi)</th>
<th>Thermal axial/hoop (ksi)</th>
<th>Residual axial/hoop (ksi)</th>
<th>Total axial/hoop (ksi)</th>
<th>Maximum axial/hoop (ksi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot leg roll transition, no sludge</td>
<td>5/11</td>
<td>-7/-7</td>
<td>65/75</td>
<td>63/79</td>
<td>79</td>
</tr>
<tr>
<td>Hot leg roll transition, with sludge</td>
<td>5/11</td>
<td>0/0</td>
<td>65/75</td>
<td>70/86</td>
<td>86</td>
</tr>
<tr>
<td>At tube support plate, no denting</td>
<td>5/11</td>
<td>0/0</td>
<td>-1/-25</td>
<td>4/-14</td>
<td>4</td>
</tr>
<tr>
<td>At tube support plate, with denting</td>
<td>0/0</td>
<td>0/0</td>
<td>60/60</td>
<td>60/60</td>
<td>60</td>
</tr>
<tr>
<td>Row 1 U-bend</td>
<td>5/11</td>
<td>-4/-4</td>
<td>100/100</td>
<td>101/107</td>
<td>107</td>
</tr>
<tr>
<td>Row 2 U-bend</td>
<td>5/11</td>
<td>-4/-4</td>
<td>67/67</td>
<td>68/74</td>
<td>74</td>
</tr>
<tr>
<td>Cold leg roll transition, no sludge</td>
<td>5/11</td>
<td>-2/-2</td>
<td>65/75</td>
<td>68/85</td>
<td>84</td>
</tr>
<tr>
<td>Cold leg roll transition, with sludge</td>
<td>5/11</td>
<td>0/0</td>
<td>65/75</td>
<td>70/86</td>
<td>86</td>
</tr>
</tbody>
</table>

Table 18. Estimated stress levels for various locations on the inside surface of steam generator tubing (1 ksi = 6.895 MPa) (adapted from [33])

6.1.3. Stress Intensity Factor

As shown in Eqs. (7) and (8), CGR is dependent on the stress intensity factor, $K$, which in turn is a function of crack size, applied stress, and the geometric factor. The cracks analyzed here begin as semielliptical surface cracks. Newman and Raju developed an empirical stress intensity factor equation for semielliptical cracks [39]. In their formulation, the geometric factor can be described in terms of crack depth-to-length and depth-to-wall thickness ratios. Application of parameters described in Table 17 shows that the geometric factor ranges from 0.72 to 1.04. However, when using Scott’s equation, a constant value of 0.93 is used for the geometric factor without adjusting for
the crack depth-to-wall thickness relationship. This was in part done to allow for slow initial crack growth and the development of crack length distribution after 11 years of operation similar to the distribution seen at Ringhals Unit 4 SG discussed later in this chapter.

6.2. State-dependent Risk Model

6.2.1. General Overview

The state-dependent risk model applies a probabilistic treatment to Scott’s empirical PWSCC model, outlined in Section 5.3.2, by considering the likelihood of crack initiation, effectiveness of surveillance, and susceptibility to various plant operating conditions. The results of the model can be described in terms of potential for SG tube rupture and consequently expressed in terms of core damage frequency.

Industry records indicate that all steam generators have been replaced due to various degradation mechanisms long before reaching 40 years of plant operation. As a result, the risk model presented here focuses on a 40-year lifetime of a nuclear power plant divided into 20 two-year cycles, each of which is assumed to correspond to one refueling cycle. It is also assumed that during each cycle some number of cracks is initiated at the surface of SG tubes, while existing cracks that were initiated in previous cycles are propagated. Each tube can contain only one dominant crack near the tube sheet. Hence, instances of crack coalescence are neglected.
The propagation continues until a crack transitions from a surface to a through-wall condition and the tube containing it becomes susceptible to various accident scenarios. A discussion of critical crack lengths is provided in Section 6.2.5. At the end of each cycle, the four SGs are inspected using eddy current testing to determine the depth and length of the cracks. The details about the success of eddy current testing are discussed in Section 6.2.6. The susceptibility to rupture induced by SLB and core damage frequency are then determined.

If a set of tubes is within a range in which a SLB could lead to rupture, the probability of induced rupture is multiplied by the frequency of SLB within that period. The probability of SLB/SGTR event that cannot be isolated (i.e. MSIV failure) is determined by multiplying by the probability of MSIV failure. The frequency of SLB/MSIV/SGTR event is just the assessed probability for the cycle divided by the duration of the cycle. There is some associated frequency of core meltdown in the short term when accompanied by failure of ECCS and in the long term by failure during recirculation (particularly in the event of MSIV failure).

6.2.2. SLB Initiating Event

Over decades, U.S. NPPs have implemented strict and improved feedwater control programs that allow for longer component life and safer operation. Because of a number of pipe ruptures that have been experienced in the carbon steel piping of the power conversion portion of NPPs, every U.S. plant now has a FAC program to help identify susceptible areas of the plant and surveillance procedures to identify the onset of
wall thinning. However, the availability of information about these programs at actual nuclear power plants is largely limited and proprietary. For this reason, the effort undertaken in this thesis to develop a state-dependent approach to assessing reactor risk has focused on steam generator tube corrosion rather than on the assessment of the time dependent risk of a steam line break. Because the FAC process requires some period of time for wastage to occur before the piping reaches a point at which a break could occur, this wear-in time has been treated simplistically. The initial degradation phase is modeled as being equivalent to the rupture of an elbow downstream of a tee in feedwater piping that occurred at Surry Unit 2 in 1986. This accident has been described in more detail in Section 4.2.4. The KWU-FAC model used with conditions present at Surry, estimated in Table 14, predicts a failure after 9.4 years. This is equivalent to an initiating event occurring during the fifth cycle according to the proposed two-year cycle analysis. Following this phase of initial degradation of piping, a constant frequency of SLB occurrence has been assumed. In NUREG/CR-4550 Vol. 7, the SLB initiating event has been assigned a frequency of 1.88E-3/year [19]. Consequently, during the core damage frequency assessment with SLB as the initiating event, the frequency is assumed as zero prior to the fifth cycle and 1.88E-3/year in the fifth and subsequent cycles of the analysis.

6.2.3. Crack Initiation

As mentioned in Chapter 5, crack initiation is usually analyzed using statistical tools due to the lack of unified theory explaining the exact mechanisms responsible for SCC initiation. Consequently, a lognormal distribution, suggested by Staehle [40], was
used to approximate the number of cracks initiated at the beginning of each cycle. In the context of this work, the initiation phase refers to the time required for crack formation with initial length of 0.1 mm. The micrographs found in [40] indicate that microcracks can be observed at that degree of resolution. Figure 22 shows the time required to initiate SCC cracks in Alloy 600MA as a function of temperature. The temperature considered in this study, marked red in Figure 22, is 330°C, which corresponds to the hot leg temperature in a steam generator. Figure 22 at this temperature indicates a mean time of 9.3 years and a standard deviation of 3.162. Application of these parameters to the lognormal distribution shows that about 67% of tubes at the end of the 40-year lifetime have microcracks. Furthermore, an observation into the number of cracks initiated in each cycle, depicted in Figure 23, shows that cracks are introduced for about 31% of the tubes at the end of the first cycle. The number of cracks initiated in successive cycles significantly decreases over the course of time.
Figure 22. Graph of IGSCC initiation time vs. 1000/T for five heats of material from 19 mm OD tubing of Alloy 600MA (adapted from [40])

Figure 23. Differential number of cracks introduced to tubes at the beginning of each cycle
6.2.4. Crack Propagation

Crack propagation following the initiation phase, or the time required for creation of 0.1 mm axial crack, is simulated using Scott’s CGR model that was discussed in Section 5.3.2 and shown in Eq. (9). The simulated crack growth is based on Scott’s equation, including the threshold stress intensity of 9 MPa√m and the exponent of 1.16. However, the simulation does not use Scott’s crack growth amplitude. Cracks initiated at the beginning of each cycle are divided into 20 groups corresponding to 20 crack growth amplitudes shown in Table 19. This treatment better reflects varying growth rates found in actual SG tubes that are a result of local conditions such as residual stresses and temperature. The details regarding the treatment of residual stresses are provided in Section 6.1.2. Wu reported data from Ringhals Unit 4 SG on crack lengths and observed a gamma distribution of crack lengths found 11 years after plant operation [41]. The data from Ringhals Unit 4 SG along with the distribution is reproduced in Figure 24.

In this study, the crack growth amplitude is used as a multiplier in Scott’s CGR equation that produces a crack distribution with characteristics similar to those found in Ringhals distribution. This was completed by initially selecting a range of amplitudes on the order of the crack amplitude used by Scott in Eq. (9). The resulting distribution at 11 years was compared against Ringhals data and a new set of amplitudes was estimated using a statistical fit. The crack length distribution after 11 years of operation developed based Scott’s equation with modified crack growth amplitudes is shown in Figure 25. The final amplitudes used in the simulation are smaller than Scott’s value of $2.8\times10^{-11}$ by 1-2 orders of magnitude. However, this can be in part explained by lack of information
regarding the cracks in Ringhals SG and application of Scott’s growth equation to a surface crack rather than a TW crack. More specifically, it is unknown whether the data displayed in Figure 24 consists of surface cracks, TW cracks or a mixture of both types. Scott’s equation was originally developed for through-wall cracks. Therefore, the crack growth amplitude developed in his study is not necessarily applicable to surface cracks. The application of Scott’s equation outside of its initial assumptions justifies the use of modified crack growth amplitudes to allow approximating case results comparable with real-life crack growth observed in Ringhals SG.

<table>
<thead>
<tr>
<th>Group Number</th>
<th>Crack Growth Amplitude</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.18E-13</td>
</tr>
<tr>
<td>2</td>
<td>5.31E-13</td>
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</tr>
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<tr>
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<td>8.43E-13</td>
</tr>
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</tr>
<tr>
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<td>8.70E-13</td>
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</tr>
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<td>17</td>
<td>8.95E-13</td>
</tr>
<tr>
<td>18</td>
<td>9.07E-13</td>
</tr>
<tr>
<td>19</td>
<td>9.18E-13</td>
</tr>
<tr>
<td>20</td>
<td>9.28E-13</td>
</tr>
</tbody>
</table>

Table 19. Crack growth rates corresponding to 20 growth groups used to determine crack propagation
Figure 24. Observed crack lengths in Ringhals SG after 11 years of operation (adapted from [41])

Figure 25. Observed crack lengths in a simulation after 11 years of operation
6.2.5. Assessment of Critical Crack Lengths

In the simulation described in Section 6.2.3 and 6.2.4 cracks are introduced with varying growth rates throughout 20 cycles and allowed to grow until the end of the simulation. During this simulation, the state-dependent risk model identifies four critical crack lengths. These lengths correspond to tube conditions that require plugging or manifest in leakage, susceptibility to steam line break or spontaneous SG tube rupture.

The first of these occurs when the depth of the crack reaches 40% of tube wall thickness. Surveillance programs at U.S. power plants require such tubes to be plugged. Assuming a wall thickness of 1.27 mm, the plugging limit refers to a depth of 0.51 mm. This translates to a crack length of 1.52 mm if assuming a constant depth-to-length ratio of 1 to 3. Reliability methods in the nuclear industry recognize a leak-before-break (LBB) condition. In materials adhering to this criterion, a surface flaw penetrates a tube or pipe wall in a stable fashion and allows for leakage detection through surveillance programs before an unstable fracture occurs [42]. In SGs, leaking tubes can be plugged to prevent further contamination of the secondary water. A ruptured tube can experience vibrations that pose a threat to the integrity of the remaining SG tubes. Thus, plugging a leaking tube is a safer and less costly procedure than dealing with a ruptured tube. In this study, tubes with cracks that are at least 3.81 mm long reach a depth equal to the tube wall thickness and experience leakage.

Tubes with the other two critical crack lengths are susceptible to SLB-induced rupture or subject to spontaneous SGTR. Tube ruptures are driven by high stress intensity factors at the tip of a crack, which leads to an unstable crack propagation and sudden
component failure. The high stress intensity factors are dependent on the pressure differential between the primary and secondary sides of the SG and tube geometry. Clearly, the pressure differential is greater in instances of SLB with a sudden depressurization of the SG than during normal operating conditions.

NUREG/CR-6664 [43] provides Eq. (14), developed by Hahn and modified by Erdogan, to determine the critical pressures and crack sizes responsible for rupture of thin-walled internally pressurized tubes with a single TW axial crack.

\[
p_{cr} = \frac{\sigma_F h}{mR} = \frac{p_b}{m}
\]

\[
\sigma_F = k(S_Y + S_U) \text{ (with } k = 0.5 - 0.6)\]

\[
m = 0.614 + 0.481\lambda + 0.386 \cdot e^{-1.25\lambda}
\]

\[
\lambda = \left[12(1 - v^2)\right]^{1/2} \cdot \frac{c}{\sqrt{R_h}} = \frac{1.82c}{\sqrt{R_h}}
\]

\[
p_b = \frac{\bar{\sigma}h}{R}
\]

where

\(p_{cr}\) = critical pressure required for tube rupture

\(\sigma_F\) = flow stress

\(h\) = wall thickness of tube

\(R\) = mean tube radius

\(p_b\) = burst pressure of an unflawed virgin tubing

\(S_Y\) = yield strength

\(S_U\) = ultimate tensile strength
Alloy 600 material properties and information about pressure differential were applied to Eq. (14) to determine critical crack lengths that can lead to tube rupture caused by depressurization following a SLB and during normal operating conditions. These crack lengths were determined as 33.0 mm for a SLB event and 62.5 mm for a spontaneous SGTR.

6.2.6. Probabilistic Treatment of Steam Generator Tube Failure

To visualize the process explained in this section, a flowchart of the simulation and corresponding subroutines are shown in Figure 26 and Figure 27. As shown in Figure 26, the process begins by setting model parameters, including number of tubes, operating pressures, stresses, material properties, etc. Next, a simulation of crack growth in tubes is performed. At the beginning of cycle \( i \), cracks are introduced to a number of tubes according to a lognormal distribution. Within each \( i^{th} \) cycle, the tubes are divided into 20 crack growth rate groups. At the end of cycle \( i \), lengths of cracks initiated in previous cycles are updated.

The crack introduction and propagation described in the previous step can be expressed by a matrix, where \( j \) corresponds to growth rate and \( k \) corresponds to current cycle of interest. As shown in Figure 26, a group with cracks from the \( j^{th} \) growth rate and introduced in the \( i^{th} \) cycle is said to contain \( N_{ij} \) tubes. The depth and length is the same
for all $N_{i,j}$ tubes. At the end of current cycle $k$, tubes are examined to see whether they need to be plugged using the ‘Plugging’ subroutine, which is shown in Figure 27. A crack first reaches depth requiring the tube to be plugged in cycle $t$ (i.e. when $k=t$).

As seen in Figure 27, the surveillance program is only 98% effective during cycle $t$ [29]. In the remaining 2% of cases, eddy current testing fails to detect flaws because of their proximity to structures in the SG. The remaining number of unplugged and potentially susceptible tubes that continue to grow, $0.02 \cdot N_{i,j}$, is sent to a ‘SLB Susceptibility’ subroutine. The closest integer of this value is referred to as $N_{i,j}^{UPS}$. In the subsequent cycle, it is assumed that the detection probability of a flawed tube belonging to $N_{i,j}^{UPS}$ is only 50% in view of no other information about the relationship of detection probability to crack growth and location. $N_{i,j}^{UPS}$ is taken as the sample size from which a distribution of the number of tubes that will be missed again is drawn. This binomial distribution, shown in Eq. (15), is used to calculate the probability of the number of tubes belonging to $N_{i,j}^{UPS}$ that will avoid detection in the cycle immediately following cycle $t$.

$$P(x|N) = \frac{N!}{x!(N-x)!} p^x (1-p)^{N-x} \quad (15)$$

where

$N =$ number of undetected tubes during the initial surveillance test, $N_{i,j}^{UPS}$

$p =$ non-detection probability

$x =$ number of undetected tubes at the end of the current cycle
Tubes from $N_{ij}^{UPS}$ become susceptible to rupture $r$ cycles after cycle $t$ (i.e. when $k=r$). This is determined using the ‘SGTR Susceptibility’ subroutine. Given that the $k^{th}$ cycle of interest is equal to or greater than $r$, the probability of non-detection is equal to $p^k$. Thus, Eq. (15) can be modified into the form shown in Eq. (16). It allows for analysis of different scenarios of known probability with different number of unplugged tubes to estimate the impact of the number of these tubes on the consequences of an initiating event. It is postulated that for multiple failed tubes, the ability to respond to the event in time to prevent core damage is affected. Furthermore, Eq. (17) determines the probability of at least one tube failing from a set of tubes with cracks characterized by the $j^{th}$ growth rate and introduced during the $i^{th}$ cycle. In addition, it is possible to determine not only the probabilities for different number of tubes failing, but also the overall weighted tube failure probability, which is just the mean failure probability as shown in Eq. (18).

$$P(x|N,k) = \frac{N!}{x!(N-x)!} p^x (1 - p^k)^{N-x}$$  \hspace{1cm} (16)

$$P(x \geq 1|N,k) = 1 - (1 - p^k)^N$$  \hspace{1cm} (17)

$$E(x|N,k) = \sum_{x=1}^{N} x P(x|N,k) = Np^k$$  \hspace{1cm} (18)

where

$N = \text{number of undetected tubes during the initial surveillance test, } N_{ij}^{UPS}$

$p = \text{non-detection probability}$

$x = \text{number of undetected tubes}$
During the $k^{\text{th}}$ cycle, it is possible that tubes with cracks introduced during different cycles are susceptible to rupture. In other words, cracks formed during cycles $i$, $i+1$, etc., may be susceptible during the cycle of interest if $k > r$. It is assumed that cracks introduced during different cycles and belonging to different growth rates are independent. For a given rate group $j$ and cycle $k$ containing tubes with cracks that have originated during different cycles, the probability of at least one tube failing is shown in Eq. (19). During the $k^{\text{th}}$ cycle, the probability of at least one tube failing across all crack growth rates and cycles of introduction is determined using Eq. (20). The expected number of tubes failing in cycle $k$ is shown in Eq. (21).

\[
P(A_j|k) = P\left(\sum_{i=1}^{m} A_i[j, k]\right) = 1 - \prod_{i=1}^{m} [1 - P(A_{ij}|k)] \tag{19}
\]

\[
P\left(\sum_{j=1}^{20} A_j|k\right) = 1 - \prod_{j=1}^{20} [1 - P(A_j|k)] \tag{20}
\]

\[
E(x|k) = 1 + \prod_{j=1}^{20} \prod_{i=1}^{m} [1 - N_{ij}p^k] \tag{21}
\]

where

\[
P(A_{ij}|k) = P(x \geq 1|N, k)
\]

$m =$ number of cycles that introduced cracks
to tubes that are now susceptible to rupture

87
Figure 26: Flowchart showing the state-dependent risk model and CDF calculation
Figure 27: Subroutine calls made to determine plugging, SLB, and SGTR susceptibility
6.3. Results of the Risk Model

6.3.1. Failure Assessment

Timing of critical lengths responsible for tube plugging, leakage, SLB susceptibility, and spontaneous SGTR across all growth rate groups is shown in Figure 28. As expected, tubes with cracks belonging to faster growth rate groups reach these critical lengths sooner than the tubes with cracks characterized by slower CGRs. For example, a tube from the fastest growth group should be plugged after 6.5 years and begins to leak after 7.8 years. It then becomes susceptible to a SLB-induced rupture and a spontaneous SGTR after 12.7 and 15 years, respectively. In comparison, for a tube from the slowest growth group, plugging, leakage, SLB susceptibility, and SGTR susceptibility occur after 14.1, 16.8, 27.5, and 32.8 years, respectively.

Figure 28. Timing of critical crack lengths across tubes divided into 20 groups
Crack lengths for several selected growth groups during the 40-year SG lifetime are shown in Figure 29. Group 1 and Group 20 represent the slowest and fastest CGR, respectively. The rates are based on Scott’s model with the exception of the crack growth amplitude, which is a proportional constant. This explains why cracks across all groups follow a similar propagation trend. During the first 15 years of the SG lifetime, cracks are essentially of the same size and propagate at a very slow rate. For instance after 15 years, cracks belonging to group 1, 5, 10, 15, and 20 measure 2.2, 19, 36, 50, and 63 mm, respectively. In addition, there is no appreciable difference in the growth rate across the different groups. This is explained by the initial crack size of 0.1 mm, which dominates the growth equation during the early stages of the simulation, resulting in similar results across all groups. The differences between these groups become more prominent after the 15th year when the cracks start to propagate much more rapidly. At this point, the crack growth amplitude becomes more dominant and drives the growth equation, which results in significantly higher growth rates.

After the 20th year of the progression model, with the exception of Group 1, cracks grow to lengths beyond 400 mm. Such significant crack lengths hold a less meaningful physical meaning. The critical crack length required for a spontaneous SGTR is 62.5 mm. This implies that a tube would have most likely ruptured before ever reaching a length of 400 mm. Figure 28 reaffirms this by indicating that the tubes belonging to the fastest growth group reach a critical length required for spontaneous SGTR after about 15 years.
Figure 29. Crack length over the course of time for selected growth rates

Figure 30, which shows the expected number of plugged tubes as a function of cycle, indicates that first tubes are plugged in the fourth cycle of the model. This is consistent with Figure 28 that shows a first plugging event for the tubes with the fastest CGR to occur after 6.5 years, which is equivalent to the fourth cycle. As discussed in Chapter 5, SGs lose their capacity margin with 15-20% tubes plugged. With SGs containing 3592 tubes, this would occur sometime when 540 to 720 tubes are plugged. Figure 30 shows that such numbers are achieved around the fifth cycle, or after ten years. Plant owner could then select to replace the SG or if possible to replace plugs with sleeves. In practice, many of the SGs in the U.S. were replaced after about 15 years of operation. This suggests that the growth rates used in the progression model are rather aggressive. It is also possible that plants have implemented better water control systems that significantly decreased instances of SCC.
6.3.2. Induced Steam Generator Tube Rupture

The probability of at least one tube failing per SG during depressurization following a steam line break was calculated and shown in Figure 31. This curve is based on a critical crack length of 33.0 mm. During the first seven cycles, the probability of concern is equal to zero. Tubes with the fastest CGR become susceptible to SLB after 12.7 years, or during the seventh cycle. However, high initial probability of detection coupled with a small number of tubes experiencing these cracks results in the first non-zero probability of failure during the eighth cycle. The probability of at least one tube failure peaks during the ninth cycle at 55.5%. In the subsequent period, this probability gradually decreases and drops below 5% in the 15th and later cycles. This can be explained by the competitive nature of the surveillance program and the number of tubes

Figure 30. Expected number of plugged tubes during SG lifetime
to which cracks are introduced in each cycle or due to the fact that tubes that were going to rupture have already ruptured. The surveillance program is effective with an initial detection rate of 98%. As can be seen in Figure 23, most of the cracks are initiated during the first cycle after which the number of tubes affected with new cracks decreases with cycle. In the later cycles, the number of new cracks is very small, yet the surveillance continues to be effective. Therefore, with a very successful detection rate and a few cracks that propagate to rupture susceptibility, the probability of concern eventually decreases. The peak probability, occurring in the ninth cycle, primarily corresponds to the large fraction of cracks that were introduced during the first cycle and were allowed to reach critical lengths.

![Graph](image.png)

*Figure 31. Probability of at least one tube failing in the event of a SLB per SG*
6.3.3. Spontaneous Steam Generator Tube Rupture

The probability of at least one tube exceeding the critical length for spontaneous rupture during an operating cycle per SG is shown in Figure 32. The critical crack length for spontaneous SGTR was determined as 62.5 mm. The graph shows that the first non-zero probability occurs in the ninth cycle. This is again supported by Figure 28, which shows that tubes with the fastest CGR become susceptible to spontaneous SGTR after 15 years, or during the eighth cycle. However, the effectiveness of the surveillance program delays the occurrence of the first appreciable probability to the ninth cycle. The maximum probability of 25.3% occurs in the 11th cycle, after which the probability begins to decrease and falls below 5% in the 15th cycle and beyond. Averaged over the lifetime of the plant, the frequency of SGTR is assessed as approximately 0.1/year. The value used in NUREG-1150 was 0.01/year. These results do not account for the potential for sufficient leakage from multiple leaking tubes to exceed the Technical Specification limit, which could result in corrective action prior to the occurrence of a SGTR. Based on the predicted number of tubes plugged as a function of time, it also appears that the aging progression model somewhat overestimates the extent of tube degradation.

Clearly, the trend seen in Figure 32 is similar to the one seen in Figure 31. The probability of rupture peaks and then decreases due to the few cracks introduced to tubes in later cycles and the very high effectiveness of the surveillance program or due to the fact that tubes that were going to rupture have already ruptured. It takes slightly longer for tubes to develop cracks susceptible to spontaneous SGTR than to rupture induced by SLB. This is supported by a visual inspection of Figure 31 and Figure 32.
6.4. Risk Results and Discussion

The results of a SLB-induced SG tube rupture, graphed in Figure 31, were used with the event tree discussed in Section 2.2.2 to develop a core damage frequency plot. The CDF was determined by multiplying probabilities of failure per demand of various safety systems according to the sequences shown in the event tree of Figure 4. The frequency of SLB (1.88E-3/year) was multiplied by two, because a two-year cycle was considered. In addition, each sequence was also multiplied by four to account for four MSIV challenges per event. Only the steam generator that is associated with the failed MSIV is a concern related to the potential for a meltdown with containment bypass. The
resulting CDF values corresponded to a two-year refueling cycle. In the end, these frequencies were divided by two to acquire CDF per year values.

The intent of this assessment is to show how state-dependent results based on the combination of mechanistic modeling of degradation and surveillance data can be incorporated into PRA, rather than to support the credibility of the values. The CDF for the accident scenario initiated by a SLB is shown in Figure 33. This plot was created using time-averaged probabilities of failure on demand of safety systems with the exception of tube rupture probability. Consequently, the trend observed in Figure 31 translates to the CDF plot. The SLB is first considered in the fifth cycle, but does not result in the combined SLB/SGTR event because none of the SG tubes has reached a vulnerable state until the seventh cycle. For the accident with SLB initiating event, the maximum CDF of 7.9E-5/year occurs in the 20th year (tenth cycle). However, as discussed earlier, the expected number of plugged tubes projected by Figure 30 suggests that a treatment of the SG (i.e. sleeving or replacement) would be necessary after about ten years (five cycles).

In the analysis performed as part NUREG-1150, the mean core damage frequency for the Zion Nuclear Power Station was determined as 3.4E-4/year [5]. However, this value was based on multiple accident scenarios. A SGTR event scenario was also analyzed in NUREG/CR-4550 Vol. 7. However, the report does not provide a collective CDF for that event, but identifies the most important sequences belonging to the SGTR event tree. The dominant sequence from a SGTR event tree was reported to have a CDF of 1.3E-6/year [19]. The frequency of bypass events in NUREG-1150 for the Zion Plant
is 2.6E-7/year. In addition, the average probability of various SLB accident progression sequences over 40 years has been calculated and shown in Table 20. It is important to point out that the time-averaged probability of Seq. 3 is zero, because the probability of successful recirculation is conditional on presence of inventory in the sump. In case of a SLB, the inventory in the sump is lost and although the integrity of recirculation system remains unchallenged from a mechanical point of view, in reality, that system does not accomplish its goal. Without the recirculation working properly, the event tree shown in Figure 4 suggests an early core meltdown in the event of SLB/K/MSIV/SGTR.

![Figure 33. Core damage frequency initiated by a SLB](image-url)
<table>
<thead>
<tr>
<th>Sequence No.</th>
<th>Average Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5.5E-3&lt;sup&gt;1&lt;/sup&gt;</td>
</tr>
<tr>
<td>2</td>
<td>8.9E-5&lt;sup&gt;1&lt;/sup&gt;</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
</tr>
<tr>
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<td>1.8E-5</td>
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<td>4.4E-13</td>
</tr>
<tr>
<td>9</td>
<td>1.0E-6</td>
</tr>
</tbody>
</table>

Table 20. Average probability of various accident sequences over 40 years

<sup>1</sup> Not core melt sequences
Chapter 7: Conclusions and Recommendations for Future Research

Chapter 7 serves as a summary to the research findings described in this thesis. Section 7.1 describes model limitations discovered and applied throughout the study. Closely related, Section 7.2 points the discussion to future research studies in this area. A possible industry application of this study is provided in Section 7.3. Conclusions to the thesis are discussed in Section 7.4.

7.1. Model Limitations

A major source of limitations to this study came from consideration of only one mode of SG tube degradation when historically there have been a number of competitive modes that have affected SG integrity. Furthermore, the treatment of PWSCC focused only on axial cracks in the roll transition zone and did not consider other regions of the SG tubes. In addition, the initial crack size was selected as 0.1 mm due to the limits imposed by Scott’s equation. This choice was based purely on the micrographs presented by Staehle [40] and does not necessarily represent the smallest observable length of a SCC defect. The choice was in part driven by the threshold stress intensity factor of 9 MPa√m that coupled with the stresses assumed in the SG tubes required such a minimum crack size. Smaller cracks led to stress intensity factors that were smaller than the
threshold. This produced a negative CGR, which is clearly contradictory to the actual physical phenomena.

Closely related to the assumed initial crack size is the choice of a geometric factor necessary to determine the stress intensity factor. A constant value of 0.93 was assumed for the SG tube geometry. This value was not updated with crack depth or after transitioning from a surface to a TW crack. Analysis of stress concentration factors in complex geometry is computationally challenging and may require the use of finite element analysis methods.

The assumptions about the geometric factor and the initial crack size were compensated by using a set of modified crack growth amplitudes that allowed simulating growth resulting in a crack length distribution similar to the one found in Ringhals Unit 4 SG. It is unclear, however, whether the cracks represented in that study were surface defects, TW defects, or a mixture of the two.

The study described in this document also did not analyze the potential for leak before break resulting from multiple tubes at the same time. In such event, the reactor operators could potentially recognize a leakage that exceeds the limits outlined in the Technical Specification and take action prior to tube failure.

The state-dependent risk model only considered steady state operating conditions and did not account for reactor transients. The model also did not consider forces applied to the SG tubes by the tube sheet. During a sudden depressurization, tube bundles within a SG may be subjected to additional forces.
Finally, NUREG-CR 4550 Vol. 7 was used to construct the event trees for this study. However, this source did not include fault trees for the top events and only provided sets of event trees with different initiating events and combination of available AC buses. The probabilities of top events in the event trees were inferred from multiple sets of event trees provided in NUREG-CR 4550 Vol. 7.

7.2. Future Research

The major focus of this research was PWSCC in the roll transition zone that led to formation and propagation of axial cracks. However, the selected degradation mechanism presents only a limited view of the actual SG aging process. A more comprehensive study of this topic should include other crack morphologies such as circumferential and radial cracks. In addition, more regions of a SG tube subjected to PWSCC should be considered. Chapter 5 provides a discussion on these regions and main crack morphologies of interest affecting them. Furthermore, a future study in this area should analyze competing degradation mechanisms such as ODSCC or IGA.

A challenge closely tied to the selection of initial crack size was the estimation of residual and thermal stresses influenced by tube geometry and temperature difference between the primary and secondary loops. In the state-dependent risk model, these parameters were assumed based on values found in literature. However, an expanded study should consider a development of a finite element analysis model of a SG tube using industry software such as ANSYS or Abaqus. An FEA model would allow a more robust treatment of different crack sizes, applied stresses resulting not only from
operating pressure but also from tube sheet forces, temperature, and tube geometry. It is also possible that an FEA model could offer a better estimate of the geometric parameter required in estimating the stress intensity factor.

The research performed as part of this study provides a very simplistic treatment of the steam line break. Future research should be supplemented by a probabilistic treatment of the secondary steam line similar to the one performed on the steam generator. The steam line consists of components that have varying susceptibility to FAC. Thus, the dynamic analysis should be performed for a number of the most critical locations in the secondary system. An essential aspect of the analysis is the characterization of the surveillance program, including an assessment of the probability of failure of the surveillance program to identify the existence of corrosion prior to pipe rupture. In addition, the overall probabilistic treatment of degradation mechanisms should be supported by a detailed uncertainly analysis.

The results analyzed in this thesis describe scenarios involving the probability of at least one or more tubes failing. A major refinement to the proposed model should include a treatment of a varying number of tube failures. The release of radioactive materials into the secondary steam line varies based on the number of tubes failing and a leak rate dependent on the crack opening area. Such analysis may shed additional light on the plant risk due to degradation mechanisms and can provide more insights into the initiating events and the required response.
7.3. Industry Application

The research described in this thesis serves as a retrospective study and can be compared against industry records to tests its accuracy and provide more insights. A possible application of this type of study in NPPs involves incorporating it into a surveillance program. For instance, during the early years of SG lifetime, the plant operator may select a surveillance program that ensures mitigation of accidents and improves overall plant safety. A simulation code, seeded with probabilities of damage susceptibility based on industry records, can be used to supplement this type of surveillance. At the end of a cycle, the results of the plant-specific surveillance program can be compared against the simulation predictions. The prior probabilities can be updated based on the data collected during surveillance and the actual state of the plant (i.e. number of tubes plugged, observed damages, etc.). Using the posterior probabilities, the simulation code can use Bayesian inference methods to estimate the regions in the SGs that are of the greatest concern due to higher risk of damage. This type of optimization better reflects plant history and can be used to refine the surveillance program. In the end, the analysis could provide plant operator with an improved risk assessment and better predict the lifetime of crucial components that would aid in maintenance scheduling and increase plant safety.
7.4. Conclusion

Reliability of passive elements has attracted regulatory and research attention due to extension of nuclear power plant lifetimes and interest in passive systems in Generation III+ and small modular reactors. Traditional PRA methods typically do not consider failures of these elements. However, passive components become a greater concern when considering extended lifecycles and potential degradation mechanisms that can lead to accidents. The purpose of this research study was to use aging mechanisms affecting carbon steel steam line and Alloy 600 SG tubes with traditional risk assessment tools to develop a state-dependent PRA model. This was a retrospective study relying on collected industry data and established degradation models. The results presented here have a limited scope and cannot be seen as predictive of current state of the U.S. nuclear power fleet. This is mainly because nuclear power plants have implemented significant updates in water controls and many of the Alloy 600 SGs have been replaced with SGs manufactured from Alloy 690. The study, however, has demonstrated that mechanistic models of degradation mechanisms, when properly benchmarked, can be used to provide an assessment of the time-dependent effects of plant aging on risk.
References


37. Group, P.M.R.P.A.I.T., *Crack Growth Rates for Evaluating Primary Water Stress Corrosion Cracking (PWSCC) of Thick-Wall Alloy 600 Material in Material Reliability Program (MRP)2002*, EPRI.