Plant-Specific Applicability of 10 CFR 50.46 Technical Basis

A White Paper Supporting the Development of Regulatory Guidance for Applicants To Demonstrate That the Transition Break Size Specified in 10 CFR 50.46 is Applicable to Their Plants

Contents

Appendices

Figures

Executive Summary

The U.S. Nuclear Regulatory Commission (NRC) has proposed to amend Title 10, Section 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,” of the *Code of Federal Regulations* (10 CFR 50.46). This amendment will permit current power reactor licensees to implement a voluntary, risk-informed alternative to the current requirements for analyzing the performance of emergency core cooling systems (ECCS) during loss-of-coolant accidents (LOCAs). In addition, the proposed rule establishes procedures and criteria for requesting changes in plant design and procedures based upon the results of the new analyses of ECCS performance during LOCAs.

The proposed rule revision for 10 CFR 50.46 introduces a transition break size (TBS), which delineates primary system pressure boundary breaks of different sizes. The existing requirements in 10 CFR 50.46 govern consideration of breaks with sizes less than or equivalent to the TBS. Only consideration of breaks with sizes greater than the TBS will be applicable to the proposed risk-informed changes to 10 CFR 50.46.

The NRC has published two technical reports (NUREGs) that form part of the technical basis used to select a TBS for boiling-water reactors (BWRs) and pressurized-water reactors (PWRs). NUREG-1829, “Estimating Loss-of-Coolant Accident (LOCA) Frequencies through the Elicitation Process,” issued April 2008, developed generic LOCA frequency estimates of passive system failure as a function of break size for both BWR and PWR plants and considered normal operational loading and transients expected over a 60-year plant life. NUREG-1903, “Seismic Considerations for the Transition Break Size,” issued February 2008, assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. NUREG-1903 evaluated both direct failures of flawed and unflawed primary system pressure boundary components and indirect failures of nonprimary system components and supports that could lead to primary system failures.

Because of the objectives and approaches followed in these studies, unique plant attributes may result in plant-specific LOCA frequencies due to normal operational and/or seismic loading that are greater than reported in either NUREG-1829 or NUREG-1903. As a result, the Commission directed the staff to require licensees applying for plant changes under the risk-informed revision to 10 CFR 50.46 to demonstrate that the results in NUREG-1829 are applicable to their individual plants. Additionally, the Commission directed the staff to develop regulatory guidance to provide a method for establishing this justification. Because the NUREG-1903 study is also generic and not bounding, the staff has interpreted this direction to extend to these results as well.

The scope of this regulatory guidance will be limited to those primary pressure boundary piping and nonpiping systems that can support LOCA break sizes larger than the TBS. This guidance will also be limited to the design basis and requirements associated with 10 CFR 50.46 and will not pertain to design-bases or operational procedures associated with the rest of the licensing basis.

The objective of this report is to provide a proposed framework and requirements for this regulatory guidance such that applicants can apply this guidance to demonstrate that the TBS specified in 10 CFR 50.46 is applicable to their plants. The contents of this report are provided to solicit stakeholder feedback before formal regulatory guidance is drafted. As such, the contents of this report to not represent official NRC positions.

This report discusses several aspects associated with the assumptions, approaches, and results of the NUREG-1829 and NUREG-1903 studies that should be addressed when evaluating the plant-specific applicability of these reports. Additionally, this report provides methods for conducting the evaluations and identifies acceptance criteria for demonstrating the plant-specific applicability of both NUREG-1829 and NUREG-1903. The NRC may also find alternative approaches and criteria proposed by the licensee to be acceptable for performing this evaluation.

The evaluation requires that the licensee first demonstrate that the applicable systems in the plant adhere to the current licensing basis. Additionally, the evaluation requires that licensees consider the effects of unique, plant-specific attributes on the generic LOCA frequencies developed in NUREG-1829. The licensee should also evaluate the effect of proposed plant changes on both direct and indirect system failures to demonstrate that NUREG-1829 results remain applicable after any changes have been enacted. Although NUREG-1829 considered the effect of safety culture on LOCA frequencies at individual plants, the NRC anticipates that existing processes are sufficient to address any deficiencies before LOCA frequencies are affected.

An evaluation framework is also provided for determining the applicability of the NUREG-1903 assessment of direct piping failures. This framework identifies the aspects that should be considered in the plant-specific analysis, provides several options for conducting the analysis, and describes a systematic approach associated with each option. One important step is to determine whether the NUREG-1903 results can be used directly or if a plant-specific analysis is required to determine the limiting flaw sizes under rare seismic loading.

NUREG-1903 also addressed indirect piping failures caused by rare seismic loading. However, the limited analysis of indirect piping failures does not provide a sufficient technical basis for allowing generic changes to the seismic design, testing, analysis, qualification, and maintenance requirements associated with any component under the proposed risk-informed revision to 10 CFR 50.46. Any proposed changes to these criteria should be justified using a plant-specific analysis. This analysis should assess the change in risk associated with seismically induced failures of the relevant component and/or system that results from the proposed plant changes.

Abbreviations

AMP	aging management program
ANS	American National Standard
ASME	American Society of Mechanical Engineers
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
B&W	Babcock and Wilcox
BACC	boric acid corrosion control
BE	best estimate
BWR	boiling-water reactor
BWRVIP	boiling-water reactor vessel internals program
CASS	cast austenitic stainless steel
CE	Combustion Engineering
CLB	current licensing basis
cm/s^2	centimeter per square second
CVCS	chemical and volume control system
DMW	dissimilar metal weld
ECCS	emergency core cooling system
EPFM	elastic-plastic fracture mechanics
EPRI	Electric Power Research Institute
EPU	extended power uprate
F	Fahrenheit
FSAR	final safety analysis report
GALL	generic aging lessons learned
GDC	general design criterion/criteria
GE	General Electric
gpm	gallon per minute
IGSCC	intergranular stress-corrosion cracking
ISI	inservice inspection
ksi	kilopounds per square inch
LBB	leak before break
LLNL	Lawrence Livermore National Laboratory
LOCA	loss-of-coolant accident
LR	license renewal
MSI	mechanical stress improvement
N	normal operating stresses
NDE	nondestructive examination
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system

P-T	pressure-temperature
PBSC	pressure boundary structural component
PGA	peak ground acceleration
PIFRAC	piping fracture database
PTL/USE	pressure-temperature limits and upper-shelf energy
PLP	primary reactor coolant loop piping (main reactor coolant loop in PWRs or the reactor water recirculation system in BWRs)
PRA	probabilistic risk assessment
PRC/CS	pressure-retaining components and component supports
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
RCPB	reactor coolant pressure boundary
RCPBM	reactor coolant pressure boundary materials
RIS	regulatory issue summary
ROP	Reactor Oversight Process
RPV	reactor pressure vessel
RVMSP	reactor vessel materials surveillance program
RWCS	reactor water cleanup system
S_m	ASME design stress intensity allowable, class 1 components
S_Y	material yield strength
S_u	material ultimate strength
SAW	submerged arc weld
SCC	stress-corrosion cracking
SF	structural factor
SMAW	shielded metal arc weld
SS-SAW	stainless steel submerged arc weld
SRP	Standard Review Plan
SRP-LR	standard review plan-license renewal
SSE	safe-shutdown earthquake
SSI	soil-structure interaction
TBS	transition break size
TLAA	time-limited aging analysis
UB	upper bound
UHS	uniform hazard spectra
W	Westinghouse
Z-factor	ratio of the failure stress predicted from a limit-load calculation to the failure stress predicted using elastic-plastic fracture mechanics

1 Introduction

The U.S. Nuclear Regulatory Commission (NRC) has published two reports (NUREGs) that form part of the technical basis used to select boiling-water reactor (BWR) and pressurized-water reactor (PWR) transition break sizes (TBSs) for the proposed, risk-informed revision of 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,” (10 CFR 50.46) [Ref. 1]. NUREG-1829, “Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process,” issued April 2008 [Ref. 2], developed generic LOCA frequency estimates of passive system failure as a function of break size for both BWR and PWR plants and considered normal operational loading and transients expected over a 60-year plant life. NUREG-1903, “Seismic Considerations for the Transition Break Size,” issued February 2008 [Ref. 3], assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. This report evaluated both direct failures of flawed and unflawed primary system pressure boundary components and indirect failures of nonprimary system components and supports that could lead to primary system failures.

Both of these studies are generic in the sense that they are not applicable to any specific nuclear plant. The principal objective of the study documented in NUREG-1829 was to develop separate BWR and PWR piping and nonpiping passive system LOCA frequency estimates as a function of effective break size at three distinct time periods: current day (25 years fleet average), end of plant license (40 years fleet average), and end of plant license renewal (60 years fleet average). These estimates are based on the responses from an expert panel. This study obtained estimates that represent a type of group consensus. Additionally, the NUREG-1829 study reflected both the uncertainty in each panelist’s estimates as well as the diversity among the individual estimates.

The elicitation efforts described in NUREG-1829 focus on developing generic, or average, estimates for the commercial fleet and the uncertainty bounds on these generic estimates, rather than bounding values associated with one or two plants. This approach is consistent with prior LOCA frequency studies that did not consider plant-specific differences in developing LOCA frequencies for use in probabilistic risk assessment (PRA) modeling. Consequently, the elicitation panelists were instructed to consider broad differences among plants related to important variables (i.e., plant system, material, geometry, degradation mechanism, loading, mitigation/maintenance) in determining both the generic LOCA frequencies and especially the estimated uncertainty bounds. The broad differences in these important variables principally affect passive system failure, and there is generally sufficient commonality among plants to make a meaningful generic assessment.

The NUREG-1829 study also relied on several implicit and explicit assumptions regarding plant design and operation and regulatory oversight. One such assumption is that plant construction and operation comply with all applicable codes and standards required by the regulations and technical specifications. The study also assumed that regulatory oversight policies and procedures will continue to be used to identify and mitigate risk associated with plants having deficient safety practices. Another important assumption is that current regulatory oversight practices will continue to evaluate aging management and mitigation strategies to reasonably ensure that future plant operation and maintenance has equivalent or decreased risk. A related assumption inherent in this elicitation is that all future plant operating characteristics will be essentially consistent with past operating practice. The study did not consider the effects of operating profile changes because of the large uncertainty surrounding possible operational changes and the potentially wide-ranging ramifications of significant plant changes on the historical LOCA frequencies supported by operational experience.

The elicitation primarily considered the effects of primary system stresses resulting from normal plant operational cycles and transients expected over a 60-year lifetime. This choice was made because these types of loads are the most generic and they have been the basis for historical LOCA frequencies that are currently used in most internal-event[1] PRAs. Consequently, NUREG-1829 did not consider rare event loading from seismic, severe water hammer and other sources because of the strong dependency that plant-specific factors have on these stresses. However, the NRC conducted a separate research study to assess the potential impact of seismic loading on the break frequency versus break size relationship. NUREG-1903 documents the results of the seismic study.

The NUREG-1903 study evaluated seismic effects on failure frequencies associated with (1) direct failure of flawed and unflawed piping and (2) piping failure caused indirectly through the failure of other structural components and supports. The intent of this study was not to perform bounding seismic analyses that encompass all potential plant-specific variations, including site-to-site variability in the seismic hazard. Rather, the purpose was to evaluate the seismic effects associated with the proposed TBS using case studies, an evaluation of operating experience, and insights from seismic PRAs. The two principal study objectives were to (1) examine the likelihood and conditions that would result in the prediction of seismically induced breaks in piping systems with inside diameters that are greater than the proposed TBS, and (2) develop analytical procedures that can be used to perform case-specific seismic analyses. This study investigated the effect of seismic events occurring with a frequency of 10^{-5} per year or less because this LOCA frequency was used as the basis for establishing the TBS.

The study did generically demonstrate that the seismically induced failure frequency in unflawed large-diameter (i.e., inside diameter greater than the TBS) piping systems is significantly less than 10^{-5} per year, the metric for establishing the TBS. Additionally, for the cases reported in NUREG-1903, large flaws are required for failure induced by seismic events having an annual probability of exceedance of 10^{-5} and 10^{-6}. Coupled with other mitigative aspects that the study did not consider, the frequency of pipe breaks larger than the TBS are likely to be less than 10^{-5} per year. The analysis of indirect failure frequencies updated prior plant-specific studies conducted by Lawrence Livermore National Laboratory (LLNL) based on more recent seismic hazard and group motion information [Ref. 3]. For the two plant-specific indirect failure scenarios evaluated, the probabilities of indirect failures of large reactor coolant pressure boundary (RCPB) piping systems are much less than 10^{-5} per year.

Because of the objectives and approaches followed in these studies, unique plant attributes may result in plant-specific LOCA frequencies caused by normal operational and/or seismic loading that are greater than reported in either NUREG-1829 or NUREG-1903. As a result, the Commission directed staff in the staff requirements memorandum for SECY-07-0082, "Rulemaking to Make Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements; 10 CFR 50.46a, 'Alternative Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,'" dated August 10, 2007 [Ref. 4], to require applicants[2] "…to justify that the generic results in the revised NUREG-1829…are applicable to their individual plants." Additionally, the staff was directed to "…develop regulatory guidance that will provide a method for establishing this justification." Because the NUREG-1903 study is

---

1 Internal events in nuclear plant PRAs are those event sequences that are initiated inside the power plant or the electric system it serves (e.g., sequences initiated by pipe, valve, or pump failures, human actions).

2 Applicant refers to a nuclear plant licensee that proposes to make plant changes under the risk-informed revision to 10 CFR 50.46. A licensee is a holder of a license granted by the NRC to operate a commercial nuclear power plant.

also generic and not bounding, the staff has interpreted this direction to extend to these results. The staff also indicated, during a meeting of the Advisory Committee on Reactor Safeguards, that it would consider developing guidance for conducting a plant-specific seismic analysis for plant conditions that deviate substantially from the cases considered in NUREG-1903 [Ref. 2].

The objective of this report is to provide a proposed framework and requirements for this regulatory guidance such that applicants can apply this guidance to demonstrate that the TBS specified in 10 CFR 50.46 is applicable to their plants. The contents of this report are provided to solicit stakeholder feedback before formal regulatory guidance is drafted. As such, the contents of this report to not represent official NRC positions.

The remainder of this report discusses the technical basis that supports the development of regulatory guidance to evaluate the plant-specific applicability of the NUREG-1829 and NUREG-1903 studies. This guidance is for applicants wishing to enact changes under the risk-informed revision of 10 CFR 50.46, which defines an alternative regulatory basis for passive system failures larger than the TBS. The applicant can use this guidance to demonstrate that its plant is represented by the generic NUREG-1829 and NUREG-1903 studies that were used, in part, to determine the TBS. This technical basis discusses aspects related to the assumptions, approach, and results of these studies that the applicant should consider when evaluating their applicability. This report also provides acceptable methods and criteria for conducting the evaluation. It should be stressed that this guidance is only applicable to enacting risk-informed changes related to the design basis and requirements associated with 10 CFR 50.46; it does not apply to any other design or operational requirements.

The discussion first covers general plant applicability of the NUREG-1829 results (Section 2.1.1). An applicant should demonstrate the plant's adherence to its current licensing basis (CLB) (Section 2.1.1.1) to ensure consistency with relevant regulations and standard practices and also address any unique, plant-specific attributes (Section 2.1.1.2) that may affect the LOCA frequencies. Next, the applicant should evaluate the applicability of the NUREG-1829 results after proposed plant changes have been enacted (Section 2.1.2). The report discusses consideration of plant changes that may affect both direct (Section 2.1.2.1) and indirect (Section 2.1.2.2) failure modes. The report also considers the effects of a plant's individual safety culture on the NUREG-1829 results (Section 2.1.3), although the staff has determined that existing processes are sufficient to address related issues before LOCA frequencies are affected.

The report then considers issues related to the applicability of the NUREG-1903 results. A framework is described for determining whether the NUREG-1903 results can be used directly or if a plant-specific analysis is required to determine the frequency associated with direct piping failure caused by a rare seismic event (Section 2.2.2). This framework identifies the aspects that the analysis should consider, provides several options for conducting the analysis, and describes a systematic approach for conducting this analysis.

The report also addresses indirect piping failures caused by seismic loading (Section 2.2.3). The limited analysis of indirect piping failures in NUREG-1903 and elsewhere does not provide a sufficient technical basis for allowing generic changes to the seismic design, testing, analysis, qualification, and maintenance requirements for applicable components and systems under the proposed risk-informed revision to 10 CFR 50.46. If an applicant intends to pursue plant changes that affect seismic design bases and margins intended to satisfy only 10 CFR 50.46 requirements, the applicant may conduct a plant-specific analysis on the effects of the proposed plant change. This analysis should demonstrate that the risk associated with seismically induced failures is acceptable.

2 Plant-Specific Evaluation of NUREG-1829 and NUREG-1903 Applicability

The TBS in the proposed rule revision for 10 CFR 50.46 is used to delineate primary system pressure boundary breaks of different sizes. The existing requirements in 10 CFR 50.46 will continue to govern breaks with sizes less than or equivalent to the TBS. Breaks with sizes greater than the TBS will be subject to revised, risk-informed requirements that are commensurate with the low frequency associated with such events. The NUREG-1829 and NUREG-1903 results justify the presumed low frequency of primary passive system failures greater than the TBS. Therefore, an applicant will only need to evaluate those piping and nonpiping systems that can support LOCA break sizes larger than the TBS. The proposed TBS sizes for BWR and PWR plants ultimately correspond to the largest pipe sizes attached to either the main reactor coolant loop in PWRs or the reactor water recirculation system in BWRs (hereafter referred to collectively as the primary loop piping (PLP)). Therefore, the applicant's evaluation need only consider breaks in the PLP and in similarly or greater sized pressure boundary structural components (PBSCs), such as pumps, valves, the reactor pressure vessel (RPV), steam generators, and associated nozzles connecting these components to the PLP.

The applicant should consider several evaluation areas when assessing the plant-specific applicability of NUREG-1829 and NUREG-1903. These areas are related either to generic assumptions or to nonbounding aspects of the approaches and analysis that were used in the development of the NUREG-1829 and NUREG-1903 results. The next sections of this report discuss these evaluation areas. This discussion addresses the aspects within each area that the applicant should evaluate, provides methods for conducting the evaluations, and identifies acceptance criteria for evaluating the results of the evaluations. These methods and acceptance criteria are intended to be acceptable for demonstrating the plant-specific applicability of both NUREG-1829 and NUREG-1903. However, the NRC may find alternative approaches and criteria to be acceptable.

2.1 Evaluation Areas Related to NUREG-1829

2.1.1 General Plant Applicability

As mentioned previously, the expert elicitation developed generic BWR and PWR LOCA frequencies by considering the effects and relationships among the important variables that principally affect passive system failure. For a given plant system, these variables include the materials, geometry, active degradation mechanisms, loading, and mitigation and maintenance associated with the system. The expert elicitation also considered the effects of broad differences among the various reactor classes and designs (i.e., Combustion Engineering (CE), Babcock and Wilcox (B&W), Westinghouse (W), General Electric (GE)). The elicitation also assumed that the design and fabrication, inspection and mitigation, and repair and replacement requirements comply with all applicable codes and standards required by regulations and technical specifications. An additional assumption was made that any unregulated aging management and mitigation strategies comply with existing, common industry practices.

Because of the generic nature of the expert elicitation, the regulatory guidance focuses on providing an acceptable method that an applicant can use to demonstrate that the plant complies with the assumptions used in the expert elicitation. This guidance is only applicable to breaks in the PLP and PBSCs that are larger than the TBS. The PBSCs consist of larger, structural components (i.e., RPV, main coolant pumps, valves, pressurizer, steam generators) that make up the primary pressure boundary and the associated safe-ends and nozzles used to connect these components to the PLP. All other plant components and systems remain within the existing regulatory framework such that acceptable safety is maintained. Thus, the staff is not imposing any additional requirements on any other plant components or systems.

The applicant is not required to validate the assumptions that the plant design, fabrication, repair activities, and replacement activities comply with all applicable codes and standards. The PLP and PBSCs have been designed and fabricated using either the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (ASME Code) [Ref. 5], Section III, or its predecessor (e.g., ASME B31.1 [Ref. 6]) requirements. Each licensee[3] also submits its design basis and fabrication quality assurance program to the NRC under either 10 CFR 50.34, "Contents of Construction Permit and Operating License Applications; Technical Information," or 10 CFR 52.79, "Contents of Applications; Technical Information in Final Safety Analysis Report." [Ref. 7] The NRC reviews this information before granting either a construction, operating, or combined license. Similarly, either ASME Code Section III or XI provides requirements governing repair and replacement activities associated with the PLP and PBSCs. The NRC staff has reviewed the acceptability of the ASME Code Sections III and XI requirements and continually reviews new ones to ensure that these standards comply with the required regulations. The acceptability of these standards, along with any required exceptions or conditions, is governed by 10 CFR 50.55a, "Codes and Standards."

A licensee can also propose alternative requirements that deviate from the provisions of 10 CFR 50.55a. However, as required by 10 CFR 50.55a, the licensee must demonstrate that the proposed alternatives either provide an acceptable level of quality and safety or that compliance with the specified requirements result in hardship or unusual difficulty without a compensating increase in the level of quality and safety. The NRC reviews these alternatives to ensure that they comply with required regulations. If the NRC finds the alternatives acceptable, they become part of the licensee's CLB. These existing requirements provide reasonable assurance that an applicant's design, fabrication, repair, and replacement activities comply with required regulations such that no additional justification is necessary to demonstrate the applicability of the NUREG-1829 results.

The additional evaluation that an applicant should conduct to demonstrate plant-specific applicability of the NUREG-1829 generic results should address the following:

(1) adherence to the CLB, including associated regulatory guidance (e.g., Generic Letter 88-01, Supplement 1, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," dated February 4, 1992 [Ref. 8];) and industry programs (e.g., aging management, water chemistry, stress-corrosion cracking (SCC) mitigation) related to inspection and/or mitigation of age-related degradation

(2) plant-specific attributes that may increase LOCA frequencies compared to the NUREG-1829 results

As previously discussed, these additional evaluations only pertain to the PLP and PBSCs and associated age-related degradation mechanisms in these systems. The most common degradation mechanisms that can cause defects to develop in these systems are related to fatigue (thermal, mechanical, or thermal-mechanical) and either intergranular stress-corrosion cracking (IGSCC) for BWR plants or primary water stress-corrosion cracking (PWSCC) for PWR

---

[3] A licensee is a holder of a license that is regulated by the NRC to operate a commercial nuclear power plant for the purpose of generating electricity.

plants. Additionally, thermal aging is a degradation mechanism that, in certain materials, causes the material strength to increase, while the ductility and toughness decrease. This mechanism, however, does not induce flaws.

Figure 1~~Figure 1~~ provides a schematic describing an acceptable method for determining the applicability of the NUREG-1829 results to a specific plant. The evaluation of a plant's adherence to the CLB is consistent with the NRC's license renewal (LR) regulatory philosophy. Applicants may utilize plant evaluations that satisfy LR requirements, if they are still relevant, as part of the basis for demonstrating the applicability of NUREG-1829.[4] Alternatively, a separate or supplemental evaluation can be used. The analysis of plant-specific attributes contains elements that are typically addressed in a leak-before-break (LBB) evaluation. Aspects of the plant-specific analysis are also consistent with the development of risk-informed inservice inspection (ISI) plans and evaluations for LR. The applicant may use these, and other relevant evaluations, to address the effects of plant-specific attributes on LOCA frequencies. Details on the analyses to demonstrate plant applicability of the NUREG 1829 results follow.

2.1.1.1 Evaluate Adherence to the Current Licensing Basis

All PWR plant applications should address PWSCC within the PLP and PBSC. The application should describe the ISI plans and mitigation strategies for all applicable dissimilar metal welds (DMWs). The description of the mitigation strategies should identify the type of mitigation used for all applicable DMWs; describe the applicable codes or standards used in the design, fabrication, and/or implementation of the mitigation; and identify and evaluate the effect of any deviations from the applicable codes or standards. The applicant should complete mitigation of PLP and PBSC DMWs before enacting any plant changes allowed under the risk-informed revision to 10 CFR 50.46 or the applicant should demonstrate that the failure risk of unmitigated DMWs is insignificant. The NRC staff expects the ISI program associated with DMWs to be conducted in accordance with ASME draft Code Case N-770, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without the Application of Listed Mitigation Activities" [Ref. 9], and any conditions that may be imposed in 10 CFR 50.55a. The applicant should identify deviations from this ASME Code case, associated NRC conditions, and applicable ASME Section XI, Appendix VIII requirements, and evaluate the effects of these deviations on the structural integrity and failure likelihood of the DMWs.

All applicants should next evaluate whether the plant's service environment, inspection, and maintenance activities are being appropriately conducted such that they comply with the CLB and are consistent with industry guidelines and practice (i.e., programs) that address aging management strategies. NUREG-1801, "Generic Aging Lessons Learned (GALL) Report Summary" [Ref. 10], issued September 2005, addresses the applicable inspection and/or mitigation activities associated with age-related degradation. The GALL Report documents the NRC staff's basis for determining which existing industry programs are adequate without modification and which existing programs should be augmented for LR. NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1, issued September 2005 (hereafter referred to as the SRP-LR) [Ref. 11], references the GALL Report as a basis for determining the adequacy of existing programs. The SRP-LR focuses staff review guidance on areas in which existing programs should be augmented for LR.

4 Note that the LR regulatory framework is only used to demonstrate that a plant is represented by the LOCA frequencies developed in NUREG-1829. The LR regulations are not intended to imply or provide any information about the LOCA frequencies associated with a particular plant.

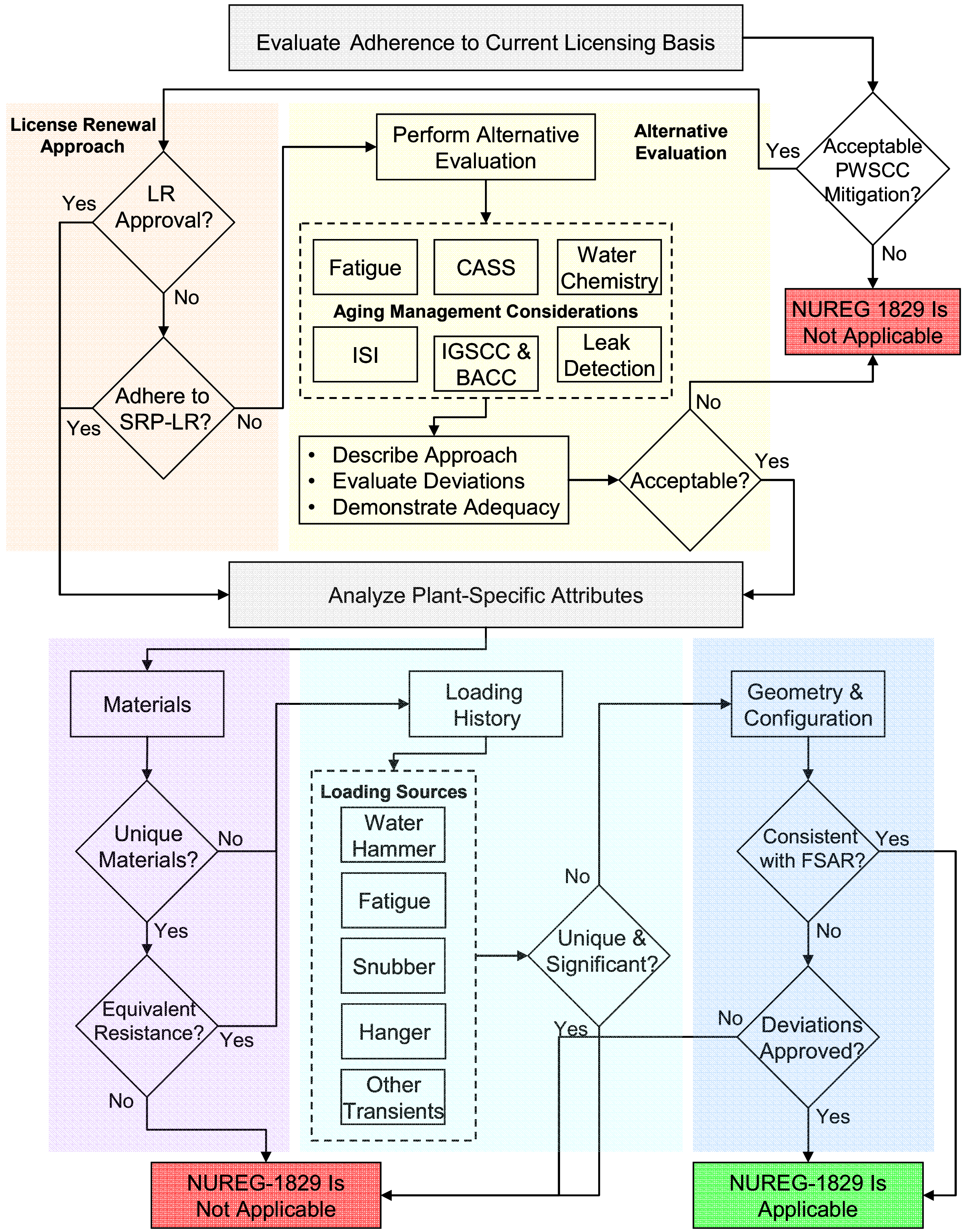


Figure 1 Evaluating general plant applicability of NUREG-1829

The GALL Report addresses aging in all major plant sections except for refueling water, chilled water, residual heat removal, condenser circulating water, and condensate storage system in PWR and BWR plants. Aging within each plant section is subsequently addressed for each principal component and/or structure within these systems. Section IV, "Reactor Vessel, Internals, and Reactor Coolant System," of the GALL Report pertains to the PLP and PBSCs that should be addressed to demonstrate the applicability of the NUREG-1829 results. This section of the GALL Report identifies the relevant aging mechanisms associated with the reactor-coolant-system materials and environment. This section also identifies the applicable aging management programs (AMPs) and indicates areas in which further plant-specific evaluation is required to demonstrate acceptability for LR. Section XI, "Aging Management Programs (AMPs)," of the GALL Report further discusses the principal elements of each AMP identified in Section IV. While the GALL Report and the SRP-LR describe acceptable methods and acceptance criteria for the AMPs, applicants can also propose alternative methods and acceptance criteria. The staff individually reviews any deviations from the GALL and SRP-LR guidance to determine their acceptability in managing age-related degradation.

Applicants that have previously demonstrated, as part of the LR process, that their AMPs for the PLP and PBSCs are acceptable can reference the staff's acceptance of these AMPs to document their adherence to the CLB (Figure 1~~Figure 1~~)[5]. However, the applicant should describe and assess the effects on the associated material degradation mechanisms of any deviations from staff-approved (i.e., approved as part of LR or other licensing action) AMPs. Alternatively, applicants that have applied for LR, but have not been granted acceptance, can describe how the AMPs for the PLP and PBSCs adhere to GALL and SRP-LR guidance (Figure 1~~Figure 1~~). The applicant should identify and describe any AMPs that deviate from SRP-LR guidance and demonstrate how these AMPs satisfy the applicable regulatory requirements associated with the CLB. The AMPs associated with the most recent LR application should be the basis for these evaluations. That is, if an applicant has applied (or been approved) for LR beyond 60 years of operation, the applicant should use the AMPs associated with this extended operation and not the AMPs associated with the original LR period which expires after 60 years.

Applicants that have not applied for LR should perform an alternative evaluation (Figure 1~~Figure 1~~) to provide the basis for the plant's adherence to the CLB. This alternative evaluation can be structured similarly to a LR application. That is, the applicant can demonstrate that the relevant AMPs either adhere to GALL and SRP-LR guidance or satisfy applicable regulatory requirements.

Several aging management considerations (Figure 1~~Figure 1~~) are relevant to PLP and PBSCs and should specifically be addressed in this alternative evaluation. For both BWR and PWR plants, applicants should consider AMPs associated with cast austenitic stainless steel (CASS) components and other piping materials, IGSCC mitigation, the boric acid corrosion control (BACC) program, the ISI plan and procedures, and the primary and secondary system water chemistries. Additionally, the evaluation should describe the time-limited aging analysis (TLAA) of fatigue and leak detection procedures in these components. For each topic, the applicant should describe the aging management approach, evaluate any deviations with GALL and/or SRP-LR requirements, and demonstrate the adequacy of the existing (or proposed) AMP or TLAA (Figure 1~~Figure 1~~). This report discusses several important aspects related to the applicability of the NUREG-1829 results for each of these aging management topics. However,

[5] Note that relief requests submitted as part of an LR application are not acceptable for either the LR application or as a basis for the evaluations described in this section.

the GALL Report and the SRP-LR provide more details on the relevant AMP and TLAA requirements.

For this alternative evaluation, the applicant should first identify and report any CASS components (i.e., pipes, elbows, pump nozzles) and any other materials that may be susceptible to thermal embrittlement using the criteria described in Reference [12]. The applicant should also indicate and describe the AMP that is followed for those components described as “potentially susceptible” in Reference [12].

The alternative evaluation should also demonstrate acceptable management of IGSCC for BWR plants. The applicant should describe ISI procedures and mitigation strategies for all applicable stainless steel piping (and welds) that are susceptible to (or are currently mitigated for) IGSCC. The description of the mitigation strategies should identify the type of mitigation used for all applicable components and discuss the applicable codes and standards used in design, fabrication, and/or implementation of the mitigation strategies. Additionally, the evaluation should indicate and describe any deviations from the applicable codes and standards; Generic Letter 88-01 staff positions [Ref. 8], ASME Section XI, Appendix VIII, requirements; or BWRVIP-75 [Ref. 13] inspection procedures. The applicant should also evaluate the effects of any deviations on the structural integrity and failure likelihood of IGSCC-susceptible components.

For PWR plants, the alternative evaluation should also demonstrate that acceptable BACC programs are being implemented. As indicated in GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” dated March 17, 1988 [Ref. 14], an acceptable program consists of systematic measures to ensure that boric acid corrosion does not lead to significant degradation of the RCPB. The BACC program should include the following:

(1) a determination of the principal locations where leaks that are smaller than the allowable technical specification limit can cause degradation of the primary pressure boundary by boric acid corrosion

(2) procedures for locating small coolant leaks (i.e., leakage rates at less than technical specification limits)

(3) methods for conducting examinations and performing engineering evaluations to establish the impact on the RCPB when leakage is located

(4) corrective actions to prevent recurrences of this type of corrosion

Applicants should demonstrate that commitments made in response to this generic letter are being implemented.

Regulatory Issue Summary (RIS) 2003-13, “NRC Review of Responses to Bulletin 2002-01, ‘Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,’” dated July 29, 2003 [Ref. 15], notes that existing BACC monitoring programs may need to be enhanced to ensure early detection and prevention of leakage resulting from through-wall cracking from passive system RCPB components. As discussed in Reference [15], enhancements may be appropriate to better identify pressure boundary leakage, identify the leakage path and targets, detect small leaks during normal power operation, and perform inspections. Specifically, ASME Code Cases N-722, “Additional Examinations for PWR

Pressure Retaining Welds in Class 1 Components Fabricated with Alloy 600/82/182 Materials," [Ref. 16] and N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Welds" [Ref. 17], provide inspection procedures for identifying pressure boundary leakage from Alloy 600 components and dissimilar metal welds fabricated from Alloys 82 and 182. The applicant should demonstrate that current inspections fulfill the requirements of 10 CFR 50.55a(g)(6)(ii)(D) and 10CFR50.55a(g)(6)(ii)(E). These requirements incorporate these code cases and contain conditions established by the NRC. The applicant's evaluation should also note any other enhancements in the BACC program to address potential weaknesses in areas discussed in Reference [15].

The applicant should also describe the ISI plan and procedures for the PLP, associated safe-ends and nozzles, and each PBSC for locations that are not susceptible to SCC for both BWR and PWR plants. This description should identify the PLP welds that are in the inspection program, the inspection periodicity of these welds, the inspection procedures, the acceptance criteria, and the quality assurance provisions. This description should also confirm that the ISI plan adheres to all applicable codes and standards, staff positions, or approved inspection procedures. Alternatively, the description should identify and provide justification for deviations from ASME Code Section XI (including Appendix VIII) requirements, an NRC-approved risk-informed ISI plan, or other governing requirements, as applicable.

Effective water chemistry protects against SCC in primary pressure boundary components in both BWR and PWR plants. For PWRs, two Electric Power Research Institute (EPRI) reports [Refs. 18, 19] provide primary and secondary system water chemistry guidelines, respectively. For BWRs, BWRVIP-130 [Ref. 20] provides primary water chemistry guidelines. The applicant should confirm that the plant is following the guidelines that are appropriate for the PLP and each PBSC. The applicant should also confirm that applicable regulatory requirements are satisfied. The evaluation should also describe the quality assurance measures adopted to ensure compliance with the water chemistry guidelines and any applicable regulations. The applicant should also evaluate the effects of any deviations from the applicable guidelines or regulations and provide a technical basis to justify any deviations.

For the PLP, PBSC safe-ends, and nozzles (i.e., those nozzles and safe-ends that are the interface between the PLP and the large primary system structural components), applicants should confirm that the cumulative usage factors for fatigue meet the requirements of 10 CFR 54.21(c)(1) [Ref. 21] over the licensing period. SRP-LR, Section 4.3, "Metal Fatigue," provides an acceptable approach for meeting these requirements. The applicant should describe alternative procedures that are used to determine the cumulative usage factors and demonstrate how these alternative procedures satisfy the requirements of 10 CFR 54.21(c)(1) over the licensing period. The fatigue analysis should consider contributions from all applicable system loads, including those arising from applicable thermally induced phenomena such as thermal loading, thermal cycling, thermal stratification, and turbulent penetration[6].

The analysis should also address the impact of environmental fatigue as required in SRP-LR, Section 4.3. Regulatory Guide 1.207, "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of the Light-Water Reactor Environment for New Reactors," issued March 2007 [Ref. 22], provides one acceptable approach for demonstrating that the fatigue analysis has considered environmental effects.

---

6 Turbulent penetration refers to the turbulent mixing of hotter and colder reactor coolant system water which can lead to alternating thermal stresses within the piping components. This can occur at nozzles and branch connections where bulk temperatures differ among the fluids in each system.

Alternatively, the applicant should demonstrate that adjustments to the fatigue life curves resulting from environmental effects (e.g., temperatures, strain rates, dissolved oxygen levels) appropriately represent or bound the plant conditions assessed in the analysis.

Finally, adequate leak-detection capabilities provide essential defense in depth to ensure that the structural integrity of the RCPB is maintained. General Design Criterion (GDC) 30, "Quality of Reactor Coolant Pressure Boundary," [Ref. 23] requires that licensees provide the means for detecting and, to the extent practical, identifying the location of the source of RCPB leakage. Technical specification limits are typically approximately 1 gallon per minute (gpm) for PWRs and 5 gpm for BWRs, which have been shown to provide sufficient margin against structural failure [Ref. 24]. Regulatory Guide 1.45, Revision 1, "Guidance of Monitoring and Responding to Reactor Coolant System Leakage," issued May 2005 [Ref. 25], addresses types of leakage, leakage separation, methods for monitoring leakage and identifying its source, monitoring system performance, seismic qualification, and leakage management. This guidance was recently updated to address progress in leak-detection technology and reduced reactor-coolant-system activity due to improved fuel integrity. Additionally, the revised guidance incorporated lessons learned from operating experience.

Regulatory Guide 1.45, Revision 1, provides one acceptable method for demonstrating that the plant's leak-detection capabilities are adequate such that the NUREG-1829 results are applicable. Alternatively, the applicant should demonstrate that the plant's leak-detection capabilities comply with technical specification limits related to identified and unidentified leakage. This demonstration should address the topic areas contained within Regulatory Guide 1.45 that are noted above (i.e., types of leakage, leakage separation, methods for monitoring leakage and identifying its source, monitoring system performance, seismic qualification, and leakage management).

2.1.1.2 Analyze Plant-Specific Attributes

This analysis will identify and evaluate any unique, plant-specific attributes that may increase LOCA frequencies compared to the generic estimates in NUREG-1829. The important plant-specific attributes to consider are related to the materials, loading history, geometry and configuration (Figure 1~~Figure 1~~), service environment, and the maintenance and mitigation strategies associated with the PLP and each PBSC. The applicant should demonstrate that either the combined effects of all unique plant attributes or the effects of each individual unique plant attribute do not result in increases in the NUREG-1829 generic LOCA frequency estimates.

A screening method is subsequently described that provides one acceptable method for demonstrating that the plant-specific LOCA frequencies are consistent with the NUREG-1829 estimate. This method is modeled after review procedures in Standard Review Plan (SRP) Section 3.6.3, "Leak-Before-Break Evaluation Procedures" [Ref. 26], that are used to evaluate water hammer, corrosion, creep damage, fatigue, erosion, and environmental conditions in piping systems. The SRP Section 3.6.3 review procedures are used to demonstrate, in part, that the system has an extremely low probability (i.e., less than 10^{-6} per year) of rupture as defined in GDC 4, "Environmental and Dynamic Effects Design Bases."[7]

2.1.1.2.1 Materials

[7] This frequency is defined in the Statement of Considerations associated with GDC 4, but not in GDC 4 itself.

The elicitation summarized in NUREG-1829 addressed the failure propensity associated with all common piping, structural materials, and welds. Particular focus was placed on primary pressure boundary materials that have experienced either inservice cracking, inservice failures, or changes in basic material properties (e.g., decreases in fracture toughness) with age. These materials include Alloy 600 base metal, Alloy 690 base metal for steam generator tubes, Alloy 82/182 weld materials, 304/316 stainless steel base and weld materials, CASS, carbon steel clad with stainless steel, and carbon steel base and weld materials (especially those with low upper shelf energies). The elicitation also addressed typical weld systems (i.e., carbon-to-carbon welds, stainless-to-stainless welds, and stainless-to-carbon welds) and the associated heat-affected zone materials. The typical locations of these materials within the primary system were also considered for the principal (i.e., W, GE, B&W, and CE) nuclear steam supply system (NSSS) designs.

Because the elicitation considered all common materials and their typical use, the applicant is not required to provide additional justification unless the applicable systems contain either unique materials not indicated in the above list or common materials in unique locations (Figure 1~~Figure 1~~) within the primary system (e.g., Alloy 600 component safe-ends rather than stainless steel). In these cases, one acceptable approach is to demonstrate that these materials have equivalent or better resistance to age-related degradation than the other common materials used in these systems (Figure 1~~Figure 1~~). For each unique material application, this demonstration should address known degradation mechanisms (i.e., those mechanisms either observed in operating experience or in representative laboratory testing), the impact of the loading history and environment on these degradation mechanisms, and applicable AMPs (e.g., augmented inspection).

2.1.1.2.2 Loading History

Because the LOCA frequency estimates were intended to be both generic and consistent with historical internal-event PRAs, the elicitation primarily considered plant operational cycles and loading histories expected to occur during a plant's extended operating license period of 60 years. Therefore, the elicitation only explicitly addressed loading events with an expected frequency greater than approximately 0.017 per calendar year, including loads associated with steady-state operation, normal startup and shutdown transients, and other expected transients (e.g., flow transients, reactor trip). Constant stresses resulting from pressure, thermal, and residual loads were differentiated from cyclical or nonconstant stresses that result from, for instance, thermal striping, heat-up/cool-down, and pressure transients. This generic evaluation did not consider rare event loading from seismic, severe water hammer, and other sources because the frequency and stress profile for these transients are strongly dependent on plant-specific factors.

The plant-specific evaluation should ensure that the loading history associated with the PLP and PBSCs is comparable to industry-wide conditions. Primary loads associated with steady-state operation and transients associated with reactor startup and shutdown have generally been comparable among plants over the last several (approximately 10) years. Additionally, these loads are governed by regulations and the plant's technical specifications such that acceptable margins are maintained. Therefore, the applicant is only required to address the likelihood and significance of effects associated with transients, or other unique loads, that depend on or result from the plant-specific configuration (i.e., those that are unique to the plant). Specifically, the applicant should consider the following loading sources (Figure 1~~Figure 1~~): water hammer, fatigue, snubber failure, hanger misadjustments, and any other nonseismic transients. More details of relevant considerations for each of these loading sources are given below.

The applicant should verify that the potential for water hammer is not likely to cause pipe rupture in the PLP or PBSC. Water hammer includes various unanticipated high-frequency hydrodynamic events such as steam hammer and water slugging. To demonstrate that component failure risk due to water hammer is acceptably low, the applicant should assess historical frequencies of water hammer events affecting the PLP or PBSC and review operating procedures and conditions to demonstrate that they are effective in precluding water hammer. Alternatively, the applicant can demonstrate that plant changes, such as the use of J-tubes, vacuum breakers, and jockey pumps, coupled with improved operating procedures have been used to successfully mitigate water-hammer events. Any measures used to abate water-hammer frequency and magnitude within the PLP or PBSC should be shown to be effective over the licensed operating period of the plant.

The applicant should also demonstrate that the applicable system does not have a history of fatigue cracking or failure. The applicant should conduct an evaluation to ensure that the potential for pipe rupture due to thermally induced, mechanically induced, and flow-induced fatigue is unlikely. Specifically, applicants must demonstrate that (1) adequate mixing of high- and low-temperature fluids occurs in the PLP so that no potential for fatigue cracking exists as a result of cyclic thermal stresses, and (2) no potential exists for vibration-induced fatigue cracking or failure. As discussed in Section 2.1.1.1, the analysis should also address the impact of environmental effects on the fatigue life curves.

Hanger misadjustments and snubber failures can significantly alter the PLP design stresses. Accordingly, the applicant should describe how proper hanger adjustment is verified during installation or reinstallation activities. This description should address applicable codes and standards followed during hanger adjustment as well as the quality assurance provisions. The failure of any snubbers that remain within the PLP could lead to higher pipe stresses than the PLP design considered. These higher stresses could result in failure within the PLP. Any age-related degradation associated with the highly stressed locations would increase the failure susceptibility. Development of the LOCA frequency estimates summarized in NUREG-1829 did not explicitly address this type of indirect failure. Therefore, the applicant should assess the reliability of any existing snubbers to demonstrate that the likelihood of piping failure resulting from a failed snubber is very small. Compliance with the technical specifications is one way to demonstrate that snubber failure rates are maintained at an acceptably low level.

Finally, based on plant-specific operating experience, the applicant should evaluate the impact on PLP and PBSC failures from other significant, nonseismically induced transients. This evaluation is required for transients other than those previously addressed in this section (i.e., water hammer, snubber failures, and thermal-mechanical fatigue). This evaluation should focus on the effects of transients induced or aided by plant-specific configurations, operating practices, or operator actions. For example, the evaluation should consider transients induced by inadvertent openings or closings of primary safety and/or relief valves during normal operations if they are caused by plant-specific features or actions or if the valves themselves are unique (Figure 1~~Figure 1~~). If the applicant identifies these types of transients, then the significance of the induced loads on the susceptibility of PLP and PBSC failure should be evaluated (Figure 1~~Figure 1~~) using, for example, ASME Code, Section XI. Section XI can be invoked to ensure that critical component flaw sizes meet appropriate acceptance criteria such that the failure likelihood is insignificant. This evaluation should assess the effects of the transients over the licensing period of the plant. Alternatively, the applicant could also describe steps taken, or planned, to mitigate these transients and evaluate their effectiveness in preventing these transients over the remaining licensing period to demonstrate that the failure risk associated with the PLP and PBSCs is insignificant.

2.1.1.2.3 Geometry and Configuration

Geometric variables affect component stress, system compliance, the propensity for a given degradation mechanism, and the likelihood of leaking versus catastrophic rupture. The geometric variables include general system information, such as piping diameter and thickness (nominal pipe size and schedule), component shape and thickness, the number of welds and their location, the types and numbers of specific piping components (e.g., elbows, tees, fittings, reducers, sockets), and the layout and design of supports and snubbers. The system configuration is related to the layout, but also specifically considers where active components such as pumps, valves, and flow orifices are located. Often, these components are connected to the primary system through flanged connections. All of these variables can influence the LOCA frequency distributions, and the NUREG-1829 elicitation considered their effects.

The design and fabrication of the PLP and PBSCs is governed by ASME Code, Section III, or earlier ASME Code, Section B31.1, requirements. Further, the NRC staff reviews and approves the design and fabrication of the primary system, as documented within the final safety analysis report (FSAR), before granting an operating license. Therefore, the plants should initially have acceptable margins with respect to both the ASME Code design loads and the regulatory requirements. Any subsequent plant changes with respect to the FSAR primary system geometry and configuration (e.g., removal of piping supports) is subject to review and approval by the NRC staff to verify that acceptable regulatory margins remain. Hence, the applicant needs only to verify that the PLP and PBSCs were constructed in accordance with the FSAR and that the current PLP and PBSC geometries and configuration (including support locations and designs) are consistent with current FSAR requirements (Figure 1~~Figure 1~~). If deviations exist, the applicant should verify that the NRC staff has reviewed and approved these deviations (Figure 1~~Figure 1~~).

2.1.1.2.4 Service Environment

The service environment determines, in part, the degradation mechanisms that are active in a specific material and the degree of degradation that occurs with continued service. Two important variables that affect degradation in the PLP and PBSCs are system temperature and reactor water chemistry (e.g., pH, dissolved oxygen concentration). The elicitation considered the effects of both typical primary system temperatures and plant-to-plant temperature differences on the LOCA frequencies. Additionally, the elicitation addressed the effects of water chemistry (i.e., hydrogenated versus nonhydrogenated and noble metal additions) and possible plant-to-plant differences in water chemistry. Differences in the plant-to-plant environments were representative of the range of conditions that existed during the timeframe of the elicitation.

Because the elicitation considered the expected effects related to the service environment, the applicant should demonstrate that the plant-specific service environment is maintained within an acceptable range that adheres to the CLB and follows applicable industry guidance. Section 2.1.1.1 of this report addresses this topic and discusses an appropriate method for demonstrating that the plant-specific environment for the PLP and PBSCs is acceptable. Therefore, no additional evidence is required to ensure that the plant-specific service environment is consistent with the elicitation considerations used to determine LOCA frequencies in NUREG-1829. Note that Figure 1~~Figure 1~~ (in the portion of the flowchart on the analysis of plant-specific attributes) does not contain a service environment block because no additional evaluation is required.

2.1.1.2.5 Maintenance and Mitigation

Maintenance and mitigation practices can also significantly affect plant-specific LOCA frequencies. These practices have been developed to maintain primary pressure boundary integrity by limiting or arresting age-related degradation. Some mitigation strategies are targeted to mitigate particular degradation mechanisms in affected systems, while others, such as nondestructive inspection, are capable of assessing several types of degradation. General maintenance and mitigation strategies applicable to the PLP and PBSCs include inspection, maintenance of water chemistry, and leak detection. Weld overlays, induction-heating stress improvement, and mechanical stress improvement are also used specifically for SCC mitigation within the PLP. The elicitation considered the mitigation and maintenance practices typically employed in the commercial nuclear industry and their affect on the LOCA frequencies.

As a result, the applicant should demonstrate that typical, approved practices are being followed for the PLP and PBSCs at the subject plant. Sections 2.1.1.1 (i.e., ISI, SCC mitigation, water chemistry, leak detection) and 2.1.1.2.2 (i.e., snubber reliability) of this report describe information that an applicant can submit to demonstrate that the plant-specific mitigation and maintenance practices are acceptable. Therefore, no additional evidence is required to demonstrate that the plant-specific maintenance and mitigation practices are consistent with those considered in NUREG-1829. Note that Figure 1~~Figure 1~~ (in the portion of the flowchart on the analysis of plant-specific attributes) does not contain a maintenance and mitigation block because no additional evaluation is required.

2.1.2 Evaluation of Plant Changes That May Affect LOCA Frequencies

Inherent in the elicitation that formed the basis for the NUREG-1829 results is the assumption that all future plant operating characteristics will be essentially consistent with past operating practice. The elicitation did not consider the effects of operating profile changes because the proposed risk-informed revision of 10 CFR 50.46 neither limits nor specifies allowable changes. Some operational changes may potentially increase the LOCA frequencies compared to those existing before the plant change. Therefore, more uncertainty existed than could be addressed in the elicitation. Additionally, operating profile changes are inherently plant-specific which was counter to the elicitation objective to develop generic frequency estimates.

The assumption that a plant's operating characteristics are constant helps to ensure that the operating experience related to PLP and PBSC degradation remains applicable over the remaining licensing period. One example of a plant change that may lead to degradation not observed in prior operating experience is a significant power uprate. A power uprate may alter relevant plant operating characteristics (e.g., temperature, environment, flow rate) such that future degradation and LOCA frequencies are increased.

Consequently, the applicant should evaluate the impact of proposed changes to the plant configuration or operating profile that would be allowed under the risk-informed revision to 10 CFR 50.46. Specifically, the applicant should assess the impacts on the LOCA frequencies associated with both direct and indirect failures of the PLP and the PBSCs. Direct failures are initiated within the PLP or PBSCs due to age-related degradation. Indirect failures of the PLP or PBSCs could result from the initial failure in other, nonprimary, pressure-boundary-retaining plant systems or components. Figure 2~~Figure 2~~ provides a schematic describing an acceptable method for evaluating the impact of plant changes on direct and indirect failure frequencies. More details on this evaluation follow.

2.1.2.1 Plant Changes That Affect Direct Failure Frequencies

The applicant should conduct an analysis of the primary system to evaluate the impact of proposed changes on the direct LOCA failure frequencies. Specifically, the analysis should assess the impact of any changes on the PLP and PBSC failure likelihood (and hence LOCA frequencies). This analysis should generally consider the effects of any changes to the principal variables considered within NUREG-1829 that are associated with the PLP and PBSC (i.e., materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation).

Option I (Figure 2~~Figure 2~~, in portion of flowchart on evaluation effect on direct failure frequencies) explicitly evaluates the impact stemming from changes related to these variables. For Option I, the applicant should first describe the approach used in the analysis and determine if the plant change affects the particular variable. For instance, if the PLP and PBSC materials will not be modified, then the plant change is not relevant to this NUREG-1829 variable. If the change is relevant, then the significance of the plant change should be assessed (Figure 2~~Figure 2~~). Significant changes are those that could increase the LOCA frequencies (Figure 2~~Figure 2~~) such that NUREG-1829 would not be applicable to the plant after the change is enacted. For instance, if the plant change increases the flow-induced vibration loading magnitude and frequency within the PLP, this may increase its failure likelihood unless appropriate mitigation is employed such that LOCA frequencies are unchanged. The review standard for extended power uprates (EPUs) [Ref. 27] provides additional guidance related to aspects of these analyses that should be considered.

The NRC staff anticipates that plant changes under the risk-informed revision of 10 CFR 50.46 will most likely impact the service environment, loading history, and/or the rate of age-related degradation. For instance, a plant change that increases the primary system temperature may increase the rate of SCC, thermal embrittlement, or the thermal loads within affected systems. In this example, new degradation mechanisms are not likely unless the temperature increases are significant. However, the applicant should also assess the effect of plant changes on the emergence of new, or previously, unobserved degradation mechanisms.

Another acceptable option (Option II in Figure 2~~Figure 2~~, portion in flowchart on evaluating effects on direct failure frequencies) uses guidance and criteria based specifically on the review standard for EPUs [Ref. 27] to evaluate the likelihood of changes in the direct failure frequency resulting from the proposed plant change. Reference 27 identifies several evaluations that are pertinent for determining the potential effects of plant changes on the failure of the PLP and PBSCs. Evaluations should address the effects of the changes on the reactor vessel materials surveillance program, the pressure-temperature limits and upper-shelf energy (PTL/USE), pressurized thermal shock (PTS), RCPB materials, LBB, chemical and volume control system (CVCS) or reactor water cleanup system (RWCS), and pressure-retaining components and component supports. Subsequent sections of this report summarize important aspects of each evaluation. However, as with Option I, each evaluation should describe the approach, assess the relevance of the plant change to the particular evaluation area or program, and determine the significance of the plant change if the change is relevant (Figure 2~~Figure 2~~). Reference 27 provides more detail on the related SRP section, the applicable regulations addressed by the evaluations, and other regulatory guidance.

2.1.2.1.1 Reactor Vessel Materials Surveillance Program

The reactor vessel material surveillance program (RVMSP) provides a means for determining and monitoring the fracture toughness of the RPV beltline materials to support analyses for ensuring the structural integrity of the RPV. The evaluation for NUREG-1829 applicability should primarily address the effects of any proposed plant change on the reactor vessel surveillance capsule withdrawal schedule. Schedules may be affected if the surveillance capsule flux or temperature increases as a result of the proposed plant change.

2.1.2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Pressure-temperature limits have been established to ensure the structural integrity of the ferritic components of the RCPB during normal operations, anticipated operational occurrences, and hydrostatic tests. The evaluation of P-T limits to demonstrate applicability of NUREG-1829 results should describe the P-T limits methodology and the calculations for the number of effective full-power years associated with the proposed plant change. This evaluation should also consider the effects of neutron embrittlement on the RPV material properties. The effects of thermal embrittlement should also be assessed for susceptible materials.

2.1.2.1.3 Reactor Coolant Pressure Boundary Materials

The reactor coolant pressure boundary materials (RCPBMs) are those materials used to fabricate the systems and components that contain the high-pressure fluids produced in the reactor. The applicant has previously provided information (described in Section 2.1.1.1) to demonstrate how aging management of these materials adheres to the CLB. The applicant has also evaluated the significance of plant-specific attributes (described in Section 2.1.1.2) on the performance of the RCPBMs and components. Therefore, any additional evaluation to demonstrate the applicability of NUREG-1829 results should only address the effects of the proposed plant changes on these materials and components. Specifically, an evaluation should consider changes related to the material specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and AMPs associated with RCPBMs.

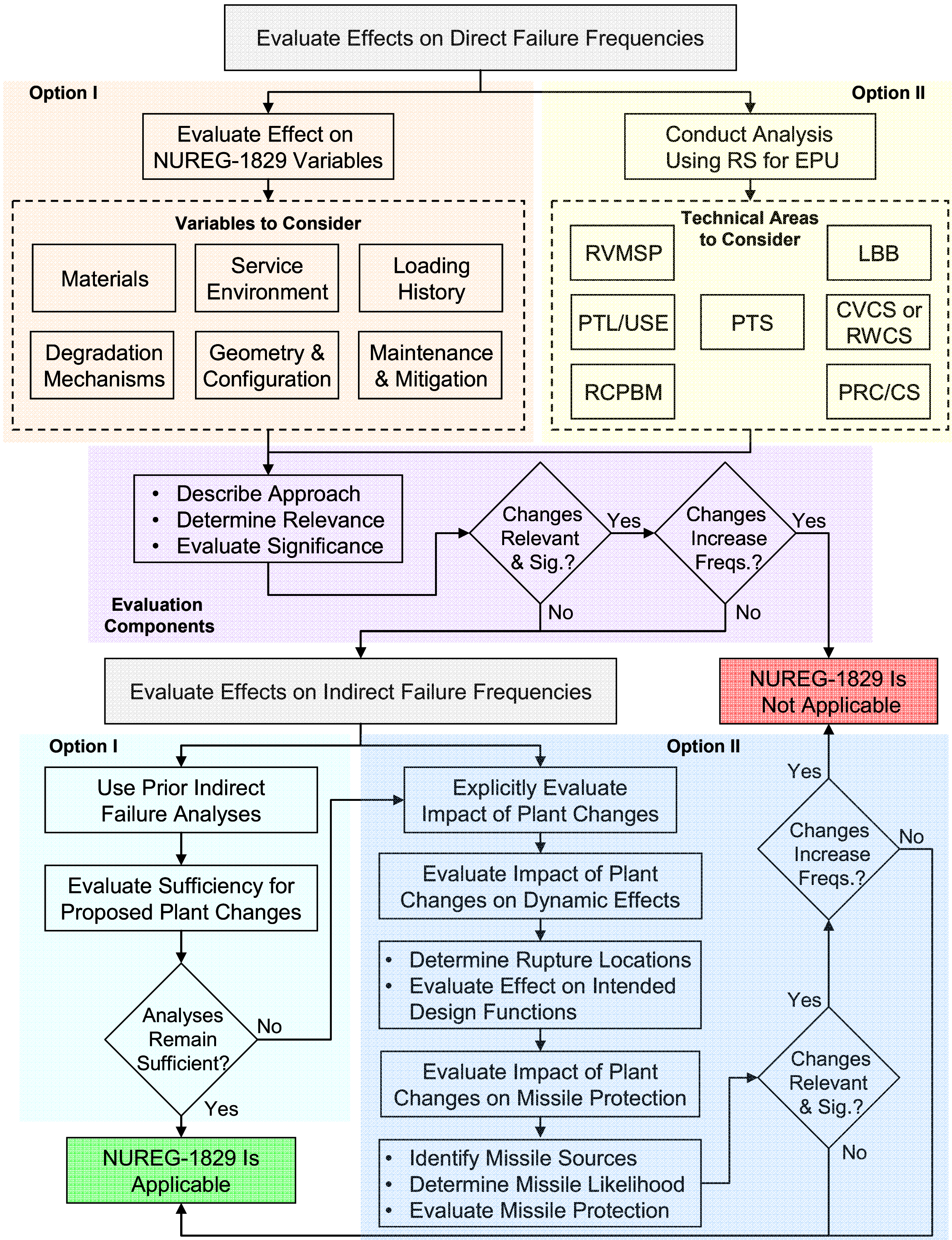
2.1.2.1.4 Pressurized Thermal Shock

The PTS evaluation is required for PWR plants and provides a means for assessing the susceptibility of the reactor vessel beltline materials to transients that arise from LOCAs, other passive system failures, and some active system failures. This evaluation provides assurance that the RPV has adequate fracture toughness. The evaluation to demonstrate the applicability of NUREG-1829 results should describe the PTS methodology and the calculations for the reference temperature, RT_{PTS}, at the expiration of the license. The evaluation should also consider the effect of the proposed plant changes on the loading transients, the fracture toughness of applicable beltline materials as altered by neutron and/or thermal embrittlement, and the likelihood of initiation and/or growth of preexisting flaws. This evaluation should address differences in the PTS results that arise from the proposed plant changes.

2.1.2.1.5 Leak Before Break

The LBB analyses provide a means for addressing the requirements for protecting against the dynamic effects of postulated pipe ruptures. The NRC approval of LBB for a plant permits the applicant to (1) remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers) and (2) redesign pipe-connected components, their supports, and their internals. For each LBB system, a deterministic fracture mechanics analysis is conducted to demonstrate that the flaw needed to rupture the piping under low-probability transient events is sufficiently larger than the flaw that would be detected by the plant's leak detection systems under normal operating conditions.

Figure 2 Evaluating the impact of plant changes



Evaluate Effects on Direct Failure Frequencies
Option I
Evaluate Effect on NUREG-1829 Variables
Variables to Consider
Materials
Service Environment
Loading History
Degradation Mechanisms
Geometry & Configuration
Maintenance & Mitigation
Option II
Conduct Analysis Using RS for EPU
Technical Areas to Consider
RVMSP
LBB
PTL/USE
PTS
CVCS or RWCS
RCPBM
PRC/CS
Describe Approach
Determine Relevance
Evaluate Significance
Evaluation Components
Changes Relevant & Sig.?
Yes
No
Changes Increase Freqs.?
Yes
No
Evaluate Effects on Indirect Failure Frequencies
NUREG-1829 Is Not Applicable
Option I
Use Prior Indirect Failure Analyses
Evaluate Sufficiency for Proposed Plant Changes
Analyses Remain Sufficient?
No
Yes
NUREG-1829 Is Applicable
Option II
Explicitly Evaluate Impact of Plant Changes
Evaluate Impact of Plant Changes on Dynamic Effects
Determine Rupture Locations
Evaluate Effect on Intended Design Functions
Evaluate Impact of Plant Changes on Missile Protection
Identify Missile Sources
Determine Missile Likelihood
Evaluate Missile Protection
Changes Increase Freqs.?
Yes
No
Changes Relevant & Sig.?
Yes
No

If LBB approval has been granted within the PLP, the applicant should conduct an LBB analysis to evaluate the effects of proposed plant changes. This analysis should identify and evaluate differences between the updated and existing LBB analysis of record and should specifically address (1) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions) and (2) indirect pipe failure mechanisms (e.g., seismic events; system overpressurizations; fires; flooding; missiles; and failures of systems, structures, and components in close proximity to the piping). Continued plant-specific applicability of the NUREG-1829 LOCA frequencies can be demonstrated if the effects of the proposed plant changes do not significantly impact the existing LBB analysis or results.

2.1.2.1.6 Chemical and Volume Control System

The CVCS and boron recovery system provide a means in PWRs for (1) maintaining water inventory and quality in the reactor coolant system, (2) supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray, (3) controlling the boron neutron absorber concentration in the reactor coolant, (4) controlling the primary water chemistry and reducing coolant radioactivity level, and (5) supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the emergency core cooling system (ECCS) in the event of postulated accidents. The applicant should, for PWR plants, evaluate the effect of proposed plant changes on the primary system water chemistry. Additionally, the applicant should demonstrate that adequate corrosion control is maintained within the PLP and PBSCs. The NUREG-1829 results remain applicable if the effects of the proposed plant changes do not significantly alter the existing water chemistry or corrosion control.

2.1.2.1.7 Reactor Water Cleanup System

The RWCS provides a means in BWRs for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant when necessary. The applicant should evaluate the effect of proposed plant changes on the primary system water chemistry as regulated by the RWCS. Additionally, the applicant should, for BWR plants, demonstrate that adequate corrosion control is maintained within the PLP and PBSCs. The NUREG-1829 results remain applicable if the effects of the proposed plant changes do not significantly alter existing water chemistry or corrosion control.

2.1.2.1.8 Pressure-Retaining Components and Component Supports

The structural integrity of pressure-retaining components and their component supports (PRC/CS) are designed in accordance with the ASME Code, Section III, Division 1, to satisfy GDC 1, “Quality Standards and Records”; 2, “Design Bases for Protection against Natural Phenomena”; 4; 14, “Reactor Coolant Pressure Boundary”; and 15, “Reactor Coolant System Design.” The applicant’s evaluation of the effect of proposed plant changes on the applicability of the NUREG-1829 LOCA frequencies should consider any effects caused by changes in the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. This analysis should also address flow-induced vibration and compare the resulting stresses and cumulative fatigue usage factors with ASME Code allowable limits. The applicant should also describe the analytical methods, assumptions, ASME Code editions, and computer programs used for these analyses. This evaluation should focus on addressing differences in the design basis and associated margins resulting from the proposed plant changes.

2.1.2.2 Plant Changes That Affect Indirect Failure Frequencies

The LOCA frequency estimates in NUREG-1829 only considered the contribution of direct piping failures. NUREG-1829 does not explicitly address failures resulting from rare seismic event loads or indirect failures, although these events contribute to the total risk of a LOCA. Section 2.2 addresses the seismic risk contribution. As previously defined, indirect PLP or PBSC failures are those that result from the initial failure of plant systems or components that are not part of the primary pressure boundary. Examples include (1) primary system overpressurization transients caused by accidents resulting from human error, fires, or flooding which cause electrical and mechanical control systems to malfunction, (2) missiles from equipment, (3) damage from moving equipment, and (4) failures of structures, systems, or components in close proximity to the PLP and PBSCs.

After considering the effect of plant changes on direct piping failures (Figure 2~~Figure 2~~), the applicant should demonstrate that the effects of plant changes on the indirect sources of pipe ruptures defined in the plant's safety analysis report remain as negligible risk contributors. The objective of this analysis is to demonstrate that the proposed plant changes negligibly increase the likelihood of indirect failures so that the NUREG-1829 results are applicable to the plant.

Two options that can be used for this analysis are provided in Figure 2~~Figure 2~~ (portion of flowchart on evaluating effects on indirect failure frequencies). Option I uses the results of prior indirect failure analyses that show compliance with existing regulations (e.g., for LBB or EPU approval). These analyses may also be applicable for demonstrating that the risk associated with indirect PLP and PBSCs failures is insignificant. The applicant should evaluate the relevance and sufficiency of these prior analyses to ensure that they adequately address impacts resulting from the proposed plant changes (Figure 2~~Figure 2~~). If the sufficiency of these prior analyses can be demonstrated, the results of NUREG-1829 are applicable to the plant (Figure 2~~Figure 2~~). If they are not sufficient, the prior analyses should be supplemented by additional evaluation.

Alternatively Option II (Figure 2~~Figure 2~~, portion of flowchart on evaluating effects on indirect failure frequencies) requires the applicant to explicitly evaluate the impact of the proposed plant changes without relying on prior indirect failure analyses. One acceptable method for conducting the explicit evaluation is based on existing LBB [Ref. 26] and EPU [Ref. 27] guidance and requirements. The following sections describe the minimum considerations that this option should address.

2.1.2.2.1 Impact of Plant Changes on Dynamic Effects

The dynamic effects associated with a pipe rupture in either primary pressure boundary piping that is smaller than the TBS or within a nonprimary pressure boundary system could impact the PLP and PBSCs. The objective of the evaluation is to demonstrate that the PLP and PBSCs remain adequately protected from the effects of these ruptures. The applicant should consider the effect of proposed design, operational, or maintenance changes within these primary and nonprimary pressure boundary systems on the design adequacy of the PLP and PBSC system. Particular emphasis should be given to the PLP and PBSC supports because support failures may lead to primary pressure boundary failures.

The applicant should either determine the rupture locations and dynamic effects or identify deviations from prior analyses resulting from the proposed changes (Figure 2~~Figure 2~~). Then, the applicant should evaluate the effects of the plant changes on the intended PLP and PBSC design functions (Figure 2~~Figure 2~~). The objective of this evaluation is to demonstrate that the intended design functions are not impaired to an unacceptable level because of pipe whip or jet impingement loadings. The evaluation should describe (1) the criteria for defining pipe break and crack locations and configurations, (2) the implementation of special programs, such as augmented ISI programs, or the use of special protective devices, such as pipe whip restraints to mitigate dynamic effects, and (3) pipe whip dynamic analyses, effects, and results, including the consideration of jet thrust and impingement forcing functions.

2.1.2.2.2 Impact of Plant Changes on Missile Protection

The applicant should next evaluate the effect of plant changes on possible PLP and PBSC failures caused by missiles (Figure 2~~Figure 2~~). Missiles could result from in-plant component overspeed failures or high and moderate pressure system ruptures. Examples are missiles that are internally generated within containment, piping failures outside containment, failures of the turbine generator, and failures of the pressurizer relief tank. The applicant's review should identify potential missile sources among applicable pressurized components and systems and high-speed rotating machinery (Figure 2~~Figure 2~~). The applicant should also identify additional missile sources (i.e., sources not identified in existing approved analysis) resulting from the proposed plant changes. The applicant's evaluation should then determine the likelihood of these missiles and evaluate the missile protection of the PLP and PBSCs (Figure 2~~Figure 2~~). The objective of this evaluation is to demonstrate that the PLP's and PBSC's missile protection is adequate.

One acceptable method for demonstrating adequate protection is to show that missile sources, the likelihood of missiles, and missile protection of the PLP and PBSC are not substantively affected by the proposed design, operational, or maintenance changes. This evaluation should focus on any changes with respect to an existing, approved missile protection analysis. For example, this analysis may demonstrate that increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or from changes in existing system configurations do not affect the likelihood of missile generation.

Alternatively, this analysis may demonstrate that system pressures and component overspeed conditions are unaffected by the proposed plant changes. The evaluation should also show that any overspeed protection features are adequate such that overspeed conditions above the design values are very unlikely. Finally, the analysis should also address the adequacy of existing PLP and PBSC missile protection barriers or systems in light of the proposed plant changes. The applicant should identify any changes in the missile protection measures resulting from these proposed changes and demonstrate that these measures adequately protect the PLP and PBSC from failures.

2.1.3 Safety Culture Considerations

Two general assumptions related to safety culture were inherent in the NUREG-1829 elicitation. The first assumption was that regulatory oversight would continue to focus on identifying and mitigating the risk associated with plants having deficient safety practices. The second assumption was based on the premise that some unknown percentage of historical passive system failures are caused, at least in part, by individual (i.e., not generic) deviations from good safety practices. The resulting assumption, which reflects the notion that human errors will continue to occur regardless of the generic safety culture, was that future LOCA frequencies related to these individual deviations would be unchanged. Because of this assumption, the elicitation panelists did not explicitly account for the effect of these individual deviations when estimating the likelihood of future age-related passive system failures.

However, the elicitation panelists did separately address the effects of generic (i.e., industry-wide) safety culture on future LOCA frequencies. Specifically, they assessed future safety culture trends and provided LOCA frequency adjustments to account for these trends. Most panelists expected either slight improvement or no change in future generic LOCA frequencies resulting from safety-culture effects. Because of this expectation, the final analysis did not explicitly adjust LOCA frequencies to account for generic safety culture effects. However, many panelists also indicated that plant-to-plant variability in safety culture could significantly effect plant-specific LOCA frequencies. Specifically, LOCA frequencies at plants with deficient safety cultures (i.e., those that deviate from accepted industry practices and regulatory requirements) could be an order of magnitude higher or more than the industry-wide estimates. For example, the NRC identified recurring performance and programmatic issues related to the safety culture as important causal factors in the reactor vessel head degradation at the Davis-Besse nuclear power plant discovered in 2002 [Ref. 28].

Since the Davis-Besse incident, and subsequent to the completion of the elicitation summarized in NUREG-1829, the NRC has taken several steps to enhance the Reactor Oversight Process (ROP) and more fully address safety culture. RIS 2006-13, "Information on the Changes Made to the Reactor Oversight Process to More Fully Address Safety Culture," dated July 31, 2006 [Ref. 29], summarizes the ROP enhancements, which are intended to achieve the following:

- provide better opportunities for the NRC staff to consider safety culture weaknesses and to encourage licensees to take appropriate actions before significant performance degradation occurs

- provide the NRC staff with a process to determine the need to specifically evaluate a licensee's safety culture after performance problems have resulted in the placement of a licensee in the degraded cornerstone column of the action matrix

- provide the NRC staff with a structured process to evaluate the licensee's safety culture assessment and to independently conduct a safety culture assessment for a licensee in the multiple/repetitive degraded cornerstone column of the action matrix

The following are some principal examples of ROP enhancements made to inspection and event response procedures to more fully address safety culture:

- The NRC revised cross-cutting areas of human performance, problem identification and resolution, and safety conscious work environment to incorporate components that are important to safety culture.

- The NRC revised the inspection procedure on identification and resolution of problems to allow inspectors to review any existing safety culture self-assessment performed by a licensee and to direct inspectors to be aware of safety culture components when selecting inspection samples.

- The NRC revised event response procedures to direct inspection teams to consider contributing causes related to the safety-culture components.

- The NRC provided additional guidance on inspecting and documenting performance deficiencies that appear to have a safety conscious work environment aspect as a contributor.

The NRC also revised the assessment process and expected NRC and licensee actions, as summarized in the ROP action matrix. The enhanced ROP continues to provide a graded approach to plant performance issues so that the regulatory response increases as performance degrades. The following is a summary of some important changes to the assessment process and action matrix:

- For the third consecutive licensee assessment letter identifying the same substantive cross-cutting issue with the same cross-cutting theme, the NRC can request that the licensee perform an assessment of safety culture.

- For licensees in the regulatory response column, the NRC should verify that the licensee's root cause, extent of condition, and extent of cause evaluations appropriately considered the safety-culture components.

- For licensees in the degraded cornerstone column, the NRC expects that the licensee's evaluation of the root and contributing causes will determine whether deficient safety-culture components caused or significantly contributed to the risk-significant performance issues. NRC inspectors are also required to independently determine whether any safety culture components caused or significantly contributed to the risk-significant performance issues. The NRC can also request that the licensee complete an independent assessment of safety culture if it determines that the licensee did not recognize that safety culture components caused or significantly contributed to the risk-significant performance issues.

- For licensees in the multiple/repetitive degraded cornerstone column, the NRC expects that the licensee will perform an independent assessment of its safety culture. Additionally, the NRC staff is required to (1) assess the licensee's independent evaluation of its safety culture and (2) independently perform an assessment of the licensee's safety culture.

The NRC expects the licensee to address and correct the safety culture issues identified within this enhanced ROP. The NRC uses quarterly reviews of plant performance to verify that identified safety culture component weaknesses are corrected and to determine what, if any, additional action the NRC will take if there are signs of declining performance. During these reviews, the staff evaluates each violation of NRC requirements to determine its effect on plant safety. If the violation has low safety significance, the NRC will not take formal enforcement action, and the plant is expected to use its corrective action program to prevent a recurrence. If the violation has higher safety significance, the staff will issue a Notice of Violation. The NRC may also issue a Notice of Violation if the licensee fails to correct a violation of low safety significance in a reasonable period of time or if the violation is found to be willful. The Notice of Violation requires the plant operator to respond formally to the NRC and identify its actions to correct the violation and the steps it will take to prevent the violation from occurring in the future.

In addition to the Notice of Violation, the NRC response plan has five levels of regulatory response, each with actions for addressing declining plant performance and subsequent violations. These actions are employed in a manner that is commensurate with decreases in safety as plant performance declines. The first three levels in the plan involve response by the appropriate regional office. Within these levels, actions may include meetings with the plant management, additional NRC inspections, and NRC oversight of plant operator self-assessment. The next two levels of regulatory response involve agency response from both Headquarters and regional offices. Stronger actions taken within these levels could include the issuance of civil orders or fines or the suspension of the plant's operating license.

As previously indicated, the NRC implemented enhancements to the ROP to more fully address safety culture in 2006 after the completion of the expert elicitation summarized in NUREG-1829. For the first time, these enhancements provide an explicit regulatory process to guide the identification, assessment, and response to cross-cutting safety culture issues. This process increases the visibility of organizational safety culture effects for licensees and the NRC and ensures that the ROP decisionmaking process explicitly considers safety culture issues. These enhancements greatly increase the likelihood that a licensee and the NRC will take appropriate actions to correct safety culture issues before significant performance degradation occurs. As a result, these enhancements are deemed sufficient for identifying potentially at-risk plants before either plant safety or LOCA frequencies are affected. Consequently, the NRC will not require action beyond the current ROP requirements and response plan provisions for applicants to demonstrate the applicability of the LOCA frequencies in NUREG-1829 in order to utilize the risk-informed revision to 10 CFR 50.46.

2.2 Evaluation Areas Related to NUREG-1903

2.2.1 Background

As previously discussed, NUREG-1903 assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. The study evaluated both direct failures of flawed and unflawed primary system pressure boundary components and indirect failures of nonprimary system components and supports that could lead to primary system failures. This section summarizes the general scope, important assumptions, and approach used in the NUREG-1903 analysis and discusses its limitations. This information is intended to provide a basis for identifying areas that an applicant should address to demonstrate that the plant-specific risk of seismically induced LOCAs is acceptably smaller than the risk associated with generic, passive system (i.e., nonseismic) LOCAs, as summarized in NUREG-1829.

The following considerations define, in part, the scope and approach used in NUREG-1903:

- Seismically induced LOCA frequencies are highly site specific and plant specific.
- Seismic hazard studies and approaches continue to evolve due, in part, to ongoing early site permit activities.
- Plant-specific information needed for the analysis (e.g., normal operating stresses, design seismic stresses, and material properties) was not available for every plant.
- Operating experience and prior PRA studies have determined that the most likely indirect PLP failures are caused by failure of major reactor coolant system components or their supports [Ref. 30].

These considerations dictated the number and type of plants that were analyzed and the hazard information used in the NUREG-1903 study. Additionally, the analysis could be limited to just the PLP to evaluate the most significant seismic risk.

All plant-specific piping design information used in NUREG-1903 was obtained from LBB analyses previously submitted by licensees. These analyses provide the most comprehensive information on normal operating (i.e., pressure, bending, membrane, deadweight, thermal expansion) and safe-shutdown earthquake (SSE) seismic stresses for pipe systems of interest. These analyses also provide other basic design information such as pipe dimensions and material properties. The LBB analyses, however, are limited to PWR plants. Similar information is not available for BWR plants.

Seismic stresses and seismically induced LOCA frequencies are proportional to the site-specific seismic hazard [Ref. 31]. Further, seismic hazard uncertainties are generally the dominant cause of uncertainties in seismic risk assessments [Ref. 3]. Therefore, the seismic hazard is an important contributor to seismic risk. NUREG-1903 uses the update of the revised LLNL hazard curves and uniform hazard spectra (UHS) [Ref. 32]. The LLNL results correspond to the 69 sites east of the Rocky Mountains. The LLNL study was used because it is the most recent, comprehensive, and publicly available set of seismic hazard information. However, the staff recognizes that there has been a significant evolution in the development and implementation of seismic hazard assessment methodology since the publication of the LLNL study [Ref. 32]. These recent efforts may impact the seismic hazard curves and UHS associated with some sites.

Because of these considerations, the NUREG-1903 analysis only explicitly analyzed PWR plants located east of the Rockies. However, the general approach used in NUREG-1903 is equally applicable to BWR plants. Additionally, the generic insights obtained from the use of the LLNL seismic hazard information in NUREG-1903 are valid regardless of the actual seismic hazard curves and UHS. Furthermore, site-specific seismic hazard information can be used to develop plant-specific results as necessary.

NUREG-1903 used the following approach to evaluate direct piping failures. The analysis considered RCPB piping with diameters larger than the proposed TBS. Applicable PWR PLP included the hot leg, cold leg, and cross-over legs. The approach combined deterministic and probabilistic elements and used sensitivity studies to address uncertainties. The evaluations included the following key elements for determining component stresses and material properties for each piping system evaluated:

- Stresses attributable to dead load, pressure, and thermal loading conditions were taken as point estimates from a database of industry LBB submittals.
- The evaluation of component-level seismic stresses for higher earthquake levels was based on the SSE stresses provided in the LBB database. However, the SSE stresses were corrected to account for ground motion and soil-structure interaction (SSI), as well as plant and piping system interaction caused by seismic loading.
- A structural response correction factor was developed to account for these known conservatisms in the design process. The correction factor was based on the seismic PRA scale factor approach [Ref. 33].

- The structural response correction factor was then used to extrapolate the best estimate (BE) SSE stresses to higher earthquake levels as point estimates.

- The higher earthquake levels correspond to peak ground accelerations with annual exceedance probabilities of 10^{-5} and 10^{-6}. These earthquake levels were determined using the LLNL mean seismic hazard information for each plant-specific site evaluated.

- Material strength and load resistance parameters were based on mean material properties in the flawed-pipe evaluations. In the unflawed-piping analysis, the allowable design stress intensity values, S_m, from Section II of the ASME Code [Ref. 5] were used to ensure consistency with the unflawed-piping failure criterion used in the analysis.

- The report assumed that unaged carbon steel and stainless steel submerged arc weld properties represent the limiting material toughness within the components.

After the component stresses and material properties were obtained for the piping system of interest, an elastic-plastic fracture mechanics evaluation based on the Z-factor approach [Ref. 34] was conducted to determine critical flaw sizes corresponding to failure due to 10^{-5} per year and 10^{-6} per year seismic events. This approach is deemed a BE evaluation because representative, and not conservative, information was sought at each step.

The analysis of direct piping failures selected 26 PWRs (see Appendix A to this report) to cover representative operating, seismic, and total stresses; a variety of pipe and weld materials with varying toughness properties; and a range of seismic hazards. The study focused on PWRs located on rock sites (24 of the 26) because these sites generally transmit higher seismic stresses to the piping systems. The study also analyzed three plants founded on soil of varying characteristics. NUREG-1903 [Ref. 3] provides more detailed information on the approach used to evaluate direct piping failures.

The analysis of seismically induced, indirect PLP failures in NUREG-1903 consisted of a scoping analysis of indirect failures caused by major reactor coolant system components or their supports. Operation experience and previous PRA insights have indicated that these indirect failures are most likely to cause direct PLP failures [Ref. 30]. The scoping analysis applied the probabilistic approach summarized in References [35, 36, 37, and 38] to two PWR plants—one W and one CE plant. The analysis used assumptions and data available from previous studies [Refs. 35, 36] and supplemented this information with the more recent LLNL seismic hazard information [Ref. 32]. As in the direct piping failure analysis, factors of safety were used to adjust SSE design quantities to BE values. These factors of safety were a combination of newly developed parameters (i.e., for seismic hazard, SSI, and structural response) and those from existing studies for equipment response and capacity. These BE SSE response quantities were extrapolated to higher stresses corresponding to 10^{-5} per year and 10^{-6} per year seismic events.

2.2.2 Direct Piping Failure Frequency Due to Seismic Loading

The analysis summarized in NUREG-1903 generically demonstrated that the seismically induced failure frequency of unflawed PLP systems (i.e., those with inside diameter greater than the TBS) is significantly less than 10^{-5} per year, the starting point for TBS selection using the NUREG-1829 LOCA frequency estimates. This result implies that the risk of failures larger than the TBS resulting from seismically induced failures is expected to be substantially less than the risk resulting from nonseismic failures. Therefore, an applicant does not need to evaluate the risk of seismically induced failures in unflawed PLP; it is neither a generic nor a plant-specific concern.

However, the risk associated with failure of seismically induced flawed PLP is more significant. For the cases studied in NUREG-1903, large circumferential flaws (i.e., crack lengths approximately 40 percent of the pipe circumference) are predicted to fail under rare seismic events when the flaw depth is a significant percentage of the wall thickness. Specifically, for a 10^{-5} per year seismic event, the critical flaw depth is at least 40 percent of wall thickness. For a 10^{-6} per year seismic event, the critical flaw depth is at least 30 percent of wall thickness. The likelihood of such a flaw existing in the PLP when a rare seismic event occurs is low and is expected to be much less than 10^{-5} per year. However, because the NUREG-1903 analysis was not intended to be bounding (e.g., thermal embrittlement of CASS and other materials was not considered), the actual critical flaw depth for a specific plant may be smaller than these estimates. Additionally, the actual failure frequency associated with any particular critical flaw size is directly proportional to the likelihood that such a flaw exists. The likelihood is subsequently a function of the inspection periodicity, resolution, and accuracy associated with the flaw location and the growth rate of the flaw as a function of time (or loading cycles).

Therefore, this guidance focuses on methods that an applicant can use to estimate the plant-specific risk associated with seismically induced failure of the PLP. One approach is to demonstrate that the existing NUREG-1903 results are applicable to the subject plant. For applicability to be demonstrated, the plant-specific PLP stresses, materials, material properties (including any aging-related property changes), and the site-specific hazard information should individually fall within, or be bounded by, the ranges considered in either NUREG-1903 or additional evaluations provided in Appendix A to this document. Additionally, the explicit combination of these plant-specific attributes should also be bounded by evaluations currently contained in either NUREG-1903 or Appendix A. If these conditions are satisfied, the bounding critical flaw depth calculated in NUREG-1903 (i.e., 40 percent for a 10^{-5} per year seismic event or 30 percent for a 10^{-6} per year seismic event) will also bound the value that would be calculated for the specific plant.

Alternatively, this report provides an analysis procedure for calculating plant-specific critical flaw sizes. An applicant can use this procedure if the existing NUREG-1903 analyses do not bound the plant's conditions or to demonstrate that the plant-specific critical flaw sizes are larger than the bounding values in NUREG-1903 or Appendix A to this report. The objective of the plant-specific flawed piping analysis is to determine critical flaw depths for long surface flaws (i.e., from NUREG-1903, $\theta/\pi = 0.8$) that correspond to a seismically induced failure frequency of 10^{-6} per year or less. This metric is chosen to ensure that the seismically induced risk of direct PLP failure is significantly less than the risk associated with failures larger than the TBS under normal operational loading (as defined in NUREG-1829). As previously discussed, the TBS was selected so that the failure risk, based on the NUREG-1829 results, was less than 10^{-5} per year. In this analysis, the applicant is then required to demonstrate that the current or augmented ISI programs associated with the PLP are sufficient to detect flaws before they reach the critical depths determined in the analysis. Figure 3~~Figure 3~~ depicts a process that can be used to determine whether the NUREG-1903 analysis can be adopted or if a plant-specific piping analysis is required. The following sections more fully describe each step in this process.

2.2.2.1 Define Analysis Requirements

The first step (Figure 3~~Figure 3~~) is to determine the scope of the analysis. The analysis should consider all piping systems having an inner diameter that is greater than the TBS, which should effectively restrict the analysis to the PLP. Next, the evaluation should identify the critical locations within the piping system. These locations are expected to have the combination of the highest normal plus SSE stresses and the lowest material toughness properties that result in the smallest critical flaw sizes. The applicant should justify the rationale for the critical locations selected. The NRC staff also expects these locations to be included in the plant's ISI program and to receive periodic examination.

The staff intends that these locations can be identified without detailed knowledge of the actual material properties and stresses within the PLP. However, subsequent steps may require that refined information. The applicant can use the ASME Code or other design stress and material information to aid in the initial selection of the critical locations. However, the applicant should also consider a location's susceptibility to degradation mechanisms that can lead to cracking (e.g., IGSCC, PWSCC) when identifying the critical locations. Additionally, the applicant should address any effects on the material properties associated with (1) the elevated loading rates associated with a seismic event (e.g., dynamic strain aging), (2) the age-related degradation of material toughness properties (e.g., thermal aging of CASS, stainless steel welds, and other applicable PLP materials), and (3) uncertainties in the material behavior when selecting critical locations.

2.2.2.2 Determine Component Stresses

The next step is to determine the stresses at the limiting locations to support subsequent analysis. Three options are acceptable for determining the component stresses.

2.2.2.2.1 Option I: Use NUREG-1903 Results

Option I (Figure 3~~Figure 3~~) allows the applicant to choose the stress values determined in NUREG-1903 for the applicable plant. NUREG-1903 analyzes 27 PWR plants. Appendix A to this report lists these plants. The NRC staff obtained critical locations, normal operating stresses (i.e., pressure, bending, membrane, deadweight, thermal expansion), and SSE stresses for these plants from LBB submittals. The SSE level stresses were then extrapolated to component stresses associated with a 10^{-6} per year seismic event using the approach described in Sections 4.5.1 and 4.5.2 of NUREG-1903 [Ref. 3]. Appendix A also lists the locations, relevant LBB information, and the associated 10^{-6} per year seismic stresses for each plant analyzed in NUREG-1903.

The applicant should determine whether the following three conditions are all satisfied to demonstrate that the NUREG-1903 stress analysis is applicable to the subject plant:

(1) The site-specific seismic hazard curve and UHS are either bounded or represented by the applicable seismic hazard curve and UHS as reported in Reference 32 to a 10^{-6} per year probability of exceedance as extended in NUREG-1903. Appendix A to Reference 32 provides design SSE peak ground accelerations for plants east of the Rocky Mountains. Part of this determination should assess whether any new information (e.g., as contained in American National Standard (ANS) 58.21 [Ref. 33]) impacts the validity of the hazard estimates used in NUREG-1903.

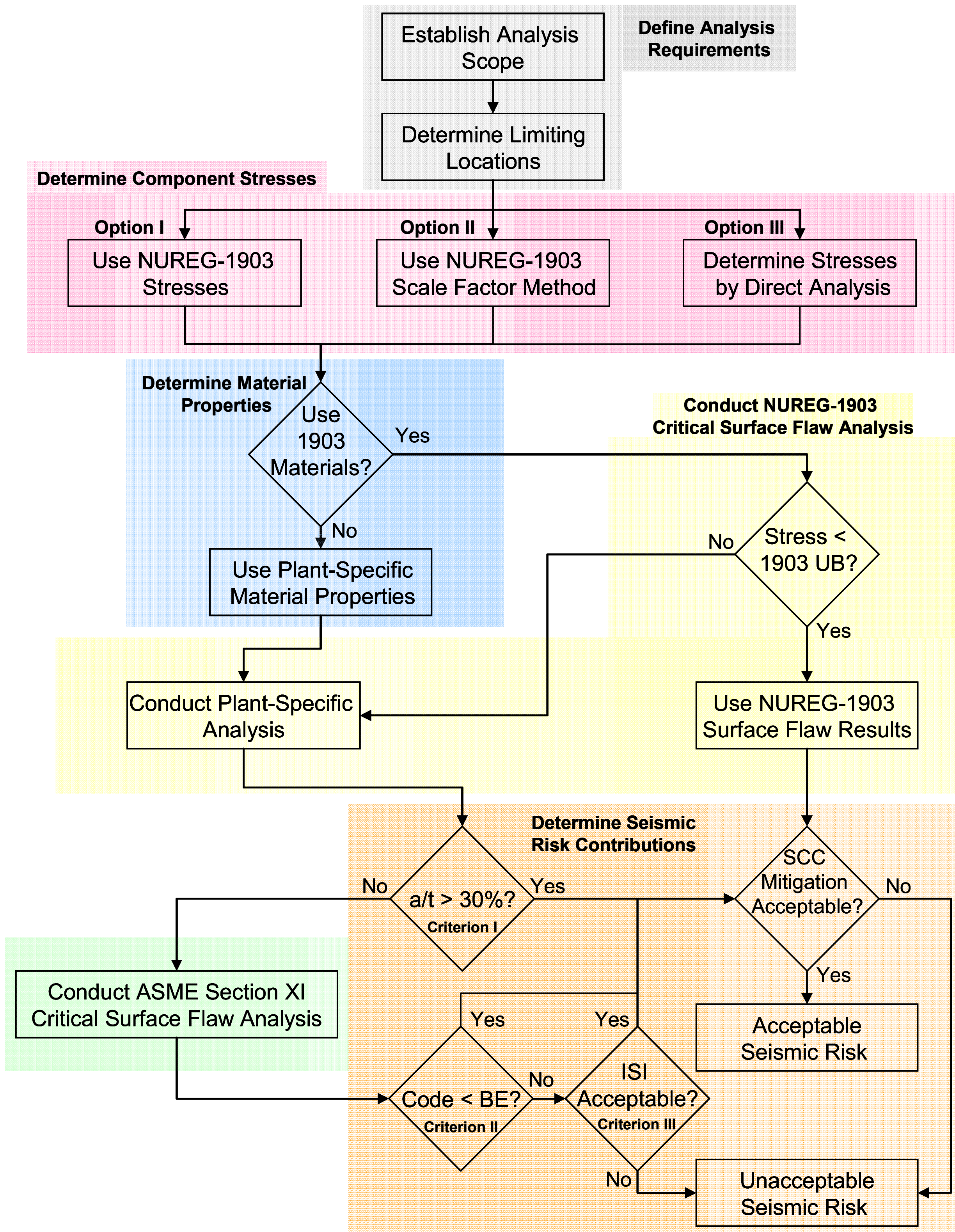


Figure 3 Evaluating seismically induced risk of direct PLP failures

(2) The critical PLP locations reported in the plant's LBB submittal are still applicable after accounting for cracking susceptibility and age-related toughness degradation at these locations. The evaluation should also address the effects of material property uncertainty.

(3) The normal operating and SSE stresses in the LBB analysis are either accurate or conservative at the critical locations.

If these conditions are satisfied, the applicant can use the plant-specific stresses developed for the NUREG-1903 analysis throughout the remainder of this analysis.

2.2.2.2.2 Option II: Use NUREG-1903 Scale-Factor Method

If the NUREG-1903 analysis did not evaluate the plant's limiting normal plus seismic component stresses (Option I, Section 2.2.2.2.1), Option II uses the scale factor method described in NUREG-1903 to determine the component stresses (Figure 3~~Figure 3~~). Appendix A to this report also provides scale factors for the seismic hazard associated with all PWR plant sites. The applicant should either determine the site-specific seismic hazard curve and UHS or use existing hazard information (e.g., as in References 30 and 32) for the site. As with Option I, part of this determination should assess whether any new information impacts the validity of the existing hazard estimates. Additionally, the seismic hazard curve and UHS should represent the ground motion response at the plant site out to a 10^{-6} per year probability of exceedance. The analysis should also appropriately address uncertainties when determining the site-specific seismic hazard information or justify the use of existing information.

Next, analysis should determine the axially oriented, normal operating, and SSE stresses as described for Service Level A and D loadings, respectively, in ASME Sections III and XI. The SSE stresses should then be extrapolated to seismic stresses representative of a 10^{-6} per year probability of exceedance by directly calculating the scale factor, as described in Section 4.5 of NUREG-1903 [Ref. 3] or by using the appropriate scale factor provided in Appendix A of this report.

2.2.2.2.3 Option III: Determine Stresses by Direct Analysis

If the NUREG-1903 analysis did not evaluate the plant's normal operating plus seismic stresses at the limiting locations as part the NUREG-1903 evaluation (Option I, Section 2.2.2.2.1), Option III allows the applicant to determine the component stresses at the critical locations by direct analysis (Figure 3~~Figure 3~~). As in Option II, the applicant should first determine the axially oriented, normal operating stresses as described for Service Level A loadings in ASME Code, Sections III and XI. Then, the applicant can perform a direct analysis to determine the seismic-induced component stresses at the limiting locations. In performing this analysis, the applicant should take the following actions:

- Use the site-specific hazard curve and ground motion (UHS) for the 10^{-6} per year probability of exceedance, which reflects all current requirements, including updates to the seismic hazard models described in Sections 2.2.2.2.1 and 2.2.2.2.2 of this report.

- Model soil/rock properties for the 10^{-6} per year seismic hazard.

- Use a reactor building dynamic model that includes all major structures (i.e., containment, internal structure, and any other major structures supported from the common foundation) and either a detailed PLP model or a simplified PLP model with appropriate mass and stiffness characteristics to represent the overall behavior of the NSSS.

- Perform SSI analyses for the given seismic input motion, soil/rock model, and structure models. (If the site condition is very stiff rock and the UHS is dominated by low frequency motion, it is conservative to treat the structure as fixed base.)

- For the detailed PLP model, use the calculated stresses at the critical locations from the combined model directly in subsequent fracture mechanics calculations

- For a simplified PLP model, use the output from the overall reactor building dynamic model (i.e., time histories or response spectra at PLP support points) at critical locations as input to a more detailed PLP model. Calculated stresses from the detailed PLP model should be used in subsequent fracture mechanics calculations.

- Address uncertainties and their effects on the PLP stresses at the critical locations.

ANS 58.21 [Ref. 33] provides more information and details related to dynamic modeling considerations. The output of this analysis is the peak axial seismic stresses at the critical locations. These stresses will subsequently be used to determine the critical flaw depths at these locations.

2.2.2.3 Determine Material Properties

The NUREG-1903 analysis assumed toughness and strength properties that are representative of carbon steel base metals and welds, as well as stainless steel submerged arc weld (SS-SAW) material. The SS-SAW J-R curve was derived in NUREG-1903 from a statistical analysis of data in the PIFRAC pipe fracture database [Ref. 39]. No statistically significant differences exist between the toughness of shielded metal arc welds (SMAWs) and submerged arc welds (SAWs). This finding is the technical basis for the current version of ASME Code, Section XI, Appendix C, which contains only one Z-factor equation for these two weld types. The mean minus one standard deviation quasi-static J-R curve from the SMAW and SAW data was modified to account for dynamic rate and cyclic loading effects that occur during an earthquake [Ref. 3]. Additionally, the NUREG-1903 evaluation used a modified J-R curve which more realistically predicted the results of large-scale piping tests [Ref. 40]. A similar analysis has also been conducted to evaluate a thermally aged SS-SAW (see Appendix B to this report) using a J-R curve from Reference 41.

If the applicant can demonstrate that the properties in the NUREG-1903 or Appendix B analysis represent or bound either the plant-specific or ASME Code properties at the critical locations, the plant-specific critical flaw sizes may be determined directly from the NUREG-1903 or Appendix B results instead of conducting a plant-specific analysis (Figure 3~~Figure 3~~). An acceptable analysis is to show that the plant-specific material toughness properties are equivalent or greater while the strength properties are equivalent or less than the properties utilized in the NUREG-1903 or Appendix B analysis.

The comparison of either the plant-specific or ASME Code and NUREG-1903 or Appendix B strength and toughness properties should consider the material properties at the operating temperature at each critical location and also account for any age-related[8] degradation of the toughness properties. Additionally, the analysis should consider any effects on the material properties caused by the elevated loading rates associated with a seismic event. Appendix B provides additional guidance for addressing the effects of elevated loading rates on material toughness (i.e., J-R curve) properties.

The properties of the plant materials should also reflect uncertainty and variability in those properties. For material toughness properties, uncertainty can be considered by obtaining a statistically significant number of J-R curves for nominally representative materials and calculating the mean minus one standard deviation J-R curve. Alternatively, an appropriate J-R curve from the ASME Code can be chosen if it can be demonstrated that it is a lower bound upon considering the uncertainty associated with the plant materials. The applicant can then compare the selected curve to the SS-SAW J-R curve used in NUREG-1903.

Similarly, for material strength properties, uncertainty can be considered by obtaining a statistically significant number of stress-strain curves for nominally representative materials and calculating the mean minus one standard deviation stress-strain curve. As before, an appropriate stress-strain curve from the ASME Code can be chosen if it can be demonstrated that it is a lower bound upon considering the uncertainty associated with the plant materials. The applicant can then compare the selected curve to the SS-SAW stress-strain curve used in NUREG-1903. The analysis can address variability in J-R and stress-strain properties by considering the impact that alloying, compositional, and microstructural differences arising during the fabrication or processing of nominally identical materials has on the measured properties. The analysis can utilize J-R and stress-strain properties from the ASME Code if the applicant demonstrates that they are lower bounds to the actual plant properties.

If the applicant cannot show that the material properties used in the NUREG-1903 or Appendix B analysis represent or bound either the plant-specific or ASME-code material properties, as appropriate, the applicant should conduct a plant-specific critical flaw size analysis (Figure 3~~Figure 3~~). Alternatively, if the applicant can demonstrate that the material properties used in either the NUREG-1903 or Appendix B analysis are bounding, the applicant may still elect to conduct a plant-specific critical flaw size analysis. This analysis may be used to credit larger critical flaw sizes than the NUREG-1903 analysis predicts. Regardless of the rationale, a plant-specific critical flaw size analysis should use either the plant-specific material strength and toughness properties or properties from the ASME Code selected using the guidance in this section

2.2.2.4 Conduct NUREG-1903 Critical Surface Flaw Analysis

2.2.2.4.1 NUREG-1903 Critical Flaw Sizes

If the material properties are bounded by those used in NUREG-1903 or Appendix B to this report, the applicant can determine plant-specific critical flaw sizes directly from the NUREG-1903 or Appendix B results as long as the normal operating plus seismic stresses are also less than the upper bound (UB) stresses evaluated in NUREG-1903 (Figure 3~~Figure 3~~). At each critical location, the analysis should combine the axially oriented, normal operating (N) and seismic stresses determined in Section 2.2.2.2 of this report to calculate the total stress (N + 10^{-}

[8] Appendix B to this report evaluates how the critical flaw sizes are affected by the decrease of toughness in SS-SAW/SMAW welds caused by thermal aging. Cast stainless steels (e.g., at elbows, pump housings, valve housings) deemed to be very sensitive to thermal aging may also require additional analyses.

^{6} seismic) associated with a 10^{-6} per year seismic event. Next, the analysis should determine whether the total stress is less than the 35 kilopounds per square inch (ksi) UB evaluated in NUREG-1903. If the value is between 10 and 35 ksi, the analysis should determine the critical flaw depth to component thickness ratio for a surface flaw having a length of θ/π = 0.8 using the curve for austenitic pipe from Figure 4-15 in NUREG-1903 [Ref. 3] or Appendix B. If the total stresses are less than 10 ksi, the analysis can assume the critical flaw depth to be 75 percent of the PLP thickness without additional calculations. Alternatively, if the total stress is greater than 35 ksi, a plant-specific analysis will be needed to determine the critical flaw depth (Figure 3~~Figure 3~~).

2.2.2.4.2 Plant-Specific Analysis

In a plant-specific analysis, the critical flaw size at each limiting location is determined using the component stresses and material properties determined in Sections 2.2.2.2 and 2.2.2.3 of this report, respectively (Figure 3~~Figure 3~~). Section 4.5.2 of NUREG-1903 [Ref. 3] describes one acceptable approach for determining the critical flaw sizes for a 10^{-6} per year seismic event. This approach is consistent with the allowable flaw size determination described in Appendix C to ASME Code, Section XI, except that no additional margin (i.e., structural factor of 1.0) is applied to the seismic stresses. The major steps in the analysis applied at each limiting location are as follows:

(1) Combine the normal operating and seismic stresses from Section 2.2.2.2 to determine the total stress (N + 10^{-6} seismic) associated with a 10^{-6} per year seismic event.

(2) If the total stress (N + 10^{-6} seismic) has been determined using elastic analysis (i.e., no correction for material plasticity), apply a plasticity correction factor to account for plasticity within the component. If the total stress (N + 10^{-6} seismic) is less than the material yield strength determined previously, this stress should be multiplied by a correction factor of 1. If the total stress (N + 10^{-6} seismic) is greater than the material yield strength determined previously, this stress should be multiplied by a correction factor of $0.5(S_y+S_u)/6.3S_m$, where S_y is the material yield strength, S_u is the material ultimate strength, and $6.3S_m$ represents the combined pressure, deadweight, and seismic stresses at failure.

(3) Determine the Z-factor correction. The Z-factor is the ratio of the failure stress predicted from a limit-load calculation to the failure stress predicted by an elastic-plastic fracture mechanics calculation. Revised Z-factors were calculated in NUREG-1903 to account for seismic-loading effects. Appendix A to this report provides these recalculated Z-factors for use in a plant-specific analysis for SS-SAW/SMAW and carbon steels. Appendix B to this report provides Z-factors for thermally aged SS-SAWs. The applicant can also determine the Z-factor for the nominal pipe diameter at each critical location using either Figure 4-8 or Figure 4-9 in NUREG-1903 for the applicable material.

(4) Determine the critical flaw depth using either the tabular or the direct analytical methods presented in ASME Code, Section XI, Appendix H, using the approach applicable for elastic-plastic failure (Articles 3500 or 3600). The assumed flaw length should be θ/π = 0.8, and the flaw should be oriented circumferentially in the worst possible location on the circumference. The analysis should set all structural factors to 1.0, and employ the Z-factor determined in Step 3. Alternatively, the applicant can determine the flaw size through direct calculation using the general analysis procedures given in NUREG-1903

and Appendix B to this report. Appendix C to this report provides a sample calculation for guidance if this later approach is chosen.

2.2.2.5 Conduct ASME Code, Section XI, Critical Surface Flaw Analysis

If the critical flaw depths calculated for each critical location in Section 2.2.2.4.2 of this report are not sufficiently large (i.e., 30 percent of through-wall thickness as defined in Section 2.2.2.6 of this report), the applicant should compare the depths to existing flaws allowed under the ASME Code (Figure 3~~Figure 3~~). The applicant may use the ASME Code, Section XI, Appendix C, flaw evaluation procedure to determine the allowable, critical surface flaw depths at each critical location for applicable materials. The applicant may also use Appendix H of ASME Code, Section XI, for materials not included in the simple Z-factor approach described in Appendix C of ASME Code Section XI. Articles 3500 or 3600 are applicable to elastic-plastic failure of circumferential flaws, and these articles should be used with all their associated requirements. Therefore, this analysis requires the structural factors and Z-factors prescribed by the ASME Code and not the less conservative factors employed in Section 2.2.2.4 of this report. This analysis should also use the normal operating and SSE stresses determined in accordance with the ASME Code requirements for Service Levels A and D loading, respectively. The applicant should not use the total seismic stresses determined for the analysis in Section 2.2.2.4 of this report in this analysis.

Additionally, the analysis should use either the representative or ASME-code material properties as selected in Section 2.2.2.3 of this report. The identical properties used in Section 2.2.2.4.2 of this report are required for this analysis in this section so that the critical flaws calculated in each section can be compared for consistent material properties. The ASME Code also allows the use of surrogate (i.e., ASME Code) material properties, but that alternative is not applicable within this analysis unless these same material properties were also employed in the Section 2.2.2.4.2 analysis. This potential limitation in the use of ASME Code material properties is the only deviation from the ASME Code, Section XI, Appendix C approach in this analysis. The ASME Code stresses and selected material properties are then used to calculate the critical surface flaw depth at each critical location for a flaw length of $\theta/\pi = 0.8$ (or $\theta/\pi > 0.75$ if using the tables in Articles 3500 or 3600 in ASME Code, Section XI). As in Section 2.2.2.4.2, the flaw at each critical location should be oriented circumferentially in the worst possible position. The applicant should compare the critical flaw depths determined in this section to the flaw depths determined in Section 2.2.2.4.2 to assess the seismic risk contributions resulting from these flaws.

2.2.2.6 Determine Seismic Risk Contributions

The final step in the analysis is to determine whether the risk associated with the direct, seismically induced failure of the PLP is significantly less than the failure risk caused by the expected loading histories considered in NUREG-1829 (Figure 3~~Figure 3~~). If any of the following three criteria are satisfied at each analyzed location, the seismic risk of direct PLP failure is considered negligible: (1) the critical flaw depths are greater than 30 percent of the through-wall thickness, (2) the critical flaw depths are greater than the ASME Code, Section XI, flaw acceptance criteria, or (3) the ISI programs are sufficient for detecting flaws before reaching the critical flaw depths calculated in Section 2.2.2.4.2 of this report. The required technical justification is increasingly rigorous for each successive criterion as the critical flaw depths decrease. More information on each criterion follows.

The first criterion is satisfied at each critical location if the critical depth for a surface flaw with a length of θ/π = 0.8, as determined in Section 2.2.2.4 of this report, is greater than 30 percent of the PLP thickness (Figure 3~~Figure 3~~). There is a high probability that existing ISI programs will detect a flaw this large before the critical flaw depth is reached. It is not intended that applicants demonstrate that current or planned inspection programs (i.e., those associated with approved AMPs, ASME criteria, or other regulatory requirements) are sufficient to reliably detect such flaws. Rather, the applicant should confirm that the ISI programs at these locations satisfy either ASME Code, Section XI (including Appendix VIII), or other applicable NRC-approved requirements.

If criterion 1 is not satisfied, the critical surface flaw depths calculated in Sections 2.2.2.4.2 (NUREG-1903 approach) and 2.2.2.5 (ASME Code, Section XI, approach) of this report should be compared at each analyzed location. The second criterion is satisfied if the more realistic, critical flaw depth (i.e., calculated using the NUREG-1903 approach) is larger than the depth determined using ASME Code, Section XI (Figure 3~~Figure 3~~). The basis for this criterion is that the more realistic critical flaw is larger than a flaw that does not meet the ASME Code, Section XI, acceptance criteria. ASME Code requires that a flaw will be dispositioned before reaching a size that would lead to failure under the presumed seismic event. Therefore, if this criterion is satisfied, the applicant should confirm that the ISI programs at these locations meet either ASME Code, Section XI (including Appendix VIII), or other NRC-approved requirements that are more conservative.

If criterion 1 or 2 are not satisfied, criterion 3 requires an applicant to demonstrate that the current ISI programs can reliably and accurately detect flaws at each critical location such that these flaws will be repaired before they reach the more realistic, critical flaw depths calculated in Section 2.2.2.4 of this report (Figure 3~~Figure 3~~). The following minimum requirements should be satisfied for the ISI programs:

- At each critical location, the applicant should establish surface and embedded flaw detectability limits for a variety of flaw depths and aspect (i.e., length-to-depth) ratios. These detectability limits should represent flaws that can be reliably detected and accurately sized by the applicable nondestructive examination (NDE) method on representative mockups. The detectability depths of the NDE method should be less than the critical flaw sizes calculated in Section 2.2.2.4 of this report.

- The applicant should demonstrate that the inspection periodicity (i.e., as determined, for example, by ASME Code, Section XI, Appendix C) is sufficient to ensure that flaws will not exceed the critical flaw depths calculated in Section 2.2.2.4 of this report between planned inspections.

- The applicant should describe the ISI programs and demonstrate that they provide reasonable assurance that the detectability limits of the NDE method can be reliably achieved in practice. The ISI description should address quality assurance provisions and also demonstrate that ISI is consistent with ASME Code, Section XI, Appendix VIII.

If any of these criteria are satisfied, the ISI programs applicable to the PLP provide reasonable assurance that flaws will be repaired before they reach depths that could cause PLP failure under rare-event, seismic loading. Otherwise, the seismic risk is unacceptable and plant changes cannot be pursued under the risk-informed revision of 10 CFR 50.46.

2.2.2.7 Effects of Stress-Corrosion Cracking Mitigation

The final step in the evaluation (Figure 3~~Figure 3~~) requires the applicant to evaluate seismic risk associated with SCC-susceptible PLP locations that have been mitigated. SCC mitigation has been performed for sensitized stainless steel materials and welds in BWR plants. Similar mitigation of dissimilar metal Inconel welds in PWR plants is underway. Many mitigation techniques are applied to susceptible regions, and they alter aspects of the original material and/or structural characteristics within these regions. For instance, mechanical stress improvement (MSI), induction heating stress improvement, weld overlay, weld inlay, and weld onlay techniques modify the residual stress magnitude and distribution within the susceptible regions. The overlay, inlay, and onlay procedures also modify the geometry and/or material combinations that originally existed in the susceptible region. Because of these alterations, these mitigation techniques may affect the thermal, seismic, deadweight, and pressure stresses with the susceptible region.

Additionally, there may be preexisting SCC flaws in these susceptible regions that were not repaired before SCC mitigation. Each SCC mitigation technique typically has an allowable maximum flaw depth that must be considered when designing and/or implementing the technique. Flaws existing before the mitigation is applied are required to be less than this maximum-allowable flaw depth [Ref. 9]. However, inspection to characterize existing indications is not always performed before implementing the mitigation technique.

The elicitation summarized in NUREG-1829 did explicitly address the effects of IGSCC mitigation on the BWR LOCA frequency estimates. NUREG-1829 did not address the effects of PWSCC mitigation on the PWR current-day LOCA frequencies because, at the time of the elicitation, industry-wide PWSCC mitigation had not been implemented. However, the elicitation panelists were knowledgeable about most of the PWSCC mitigation techniques because they are similar, or identical, to those implemented for IGSCC mitigation in BWR plants. Based on this knowledge, the elicitation panelists did consider the effects of PWSCC mitigation on future LOCA frequencies after mitigation has been adopted throughout the PWR fleet. Because the elicitation explicitly considered SCC mitigation, the applicant is only required to demonstrate, as described in Section 2.1.1.1 of this report, that SCC management satisfies applicable industry, ASME Code, and regulatory requirements.

Conversely, the analysis of seismically induced frequencies in NUREG-1903 neither explicitly nor implicitly addressed the effects of SCC mitigation on the seismic risk. Therefore, the applicant should demonstrate that there is an insignificant failure risk at SCC-mitigated locations in BWRs and PWRs due to rare (i.e., 10^{-6} per year) seismic events. One acceptable approach is to demonstrate that the mitigation has been designed and implemented such that the minimum structural factors required by the ASME Code are preserved for each service level, including SSE (i.e., Service Level D) loading as discussed in References 9, 13, and 42. Applicants should therefore confirm that the post-mitigation structural factor associated with SSE loading satisfies the ASME Code requirements. The applicant should consider the effects of the maximum-allowable, pre-mitigation flaw when determining the structural factors:

As in Section 2.1.1.1 of this report, applicants should also confirm that the ISI plan for the SCC locations adheres to all applicable codes and standards (including ASME Code, Section XI, Appendix VIII), staff positions, and/or approved inspection procedures. Specifically, the applicant should confirm the following:

(1) The pre-mitigation inspection can reliably and accurately detect flaws that are equivalent to or less than the maximum flaw depth allowed for that mitigation technique.

(2) The post-mitigation inspections can reliably and accurately detect both the growth of preexisting flaws identified in the pre-mitigation inspection and flaws that exceed the maximum flaw depth allowed for the specific mitigation technique.

(3) The inspection periodicity provides reasonable assurance that any flaw growth between scheduled inspections will not result in a violation of the minimum structural factors required by the ASME Code.

Some mitigation techniques may also credit residual stress redistribution to satisfy the minimum SSE structural factor. For these techniques, the applicant should demonstrate that the stress redistribution is still effective and provides acceptable margin for the 10^{-6} per year seismic event at the mitigation locations. The applicant can determine the seismic stresses using the approach described in Section 2.2.2.2 for this analysis. For example, MSI forms compressive stresses over the inner 30 percent of the pipe thickness. These stresses effectively prevent growth of flaws that initiate from the inner pipe wall as long as the flaw depth is less than this compressive region before MSI is applied [Refs. 43, 44]. A negligible seismic risk could be demonstrated for MSI if these stresses remain compressive for the 10^{-6} per year seismic event.

If the combined stresses do not remain compressive, the applicant can determine whether the maximum allowable pre-mitigation flaw [Ref. 9] results in significant crack growth or failure during the 10^{-6} per year seismic event using the analysis described in Sections 2.2.2.3 and 2.2.2.4 of this report. This analysis should not credit compressive stresses induced by mitigation. Alternatively, the failure propensity of the critical location can be assessed by—

(1) creating a detailed PLP model that contains the maximum allowable pre-mitigation flaw

(2) simulating the mitigation technique to predict the residual stress distribution at that location

(3) simulating the 10^{-6} per year seismic event to determine the component stresses and conducting a flaw instability analysis (as described in Sections 2.2.2.3 and 2.2.2.4 of this report) to determine whether significant crack growth or failure occurs

If the applicant demonstrates, using these or other approaches, that the mitigation design, implementation, and the ISI program leads to an acceptable seismic risk for direct PLP failure, then the applicant may apply for plant changes under the risk-informed revision of 10 CFR 50.46.

2.2.3 <u>Indirect Piping Failure Frequency Due to Seismic Loading</u>

As discussed in Section 2.2.1, the NUREG-1903 analysis considered PLP failures induced by component support failures for two PWR plants—one W and one CE design. For the two cases considered, the indirectly induced PLP frequency is substantially less than 10^{-5} per year, the starting point for selecting the TBS. Therefore, the staff expects the risk associated with these case studies to be substantially less than for PLP and PBSC failures larger than the TBS under the loading conditions evaluated in NUREG-1829. However, as with the other portions of the seismic analysis, failure evaluations of component supports are plant and site specific. Because the piping and major system configuration is unique, the component and pipe support designs vary significantly from plant to plant. Therefore, it is difficult to extrapolate the results and implications associated with this limited case study to the broader plant fleet.

SRP Section 3.9.2, Revision 3, "Dynamic Testing and Analysis of Systems, Structures, and Components," [Ref. 45] and SRP Section 3.9.3, Revision 2, "ASME Code Class 1, 2, and 3 Components and Component Supports, and Core Support Structures," [Ref. 46] contain component support and snubber acceptance criteria. Current component support and snubber designs are required, in part, to satisfy GDC 14 such that these components have an extremely low probability of abnormal leakage, rapidly propagating failure, and gross rupture. This requirement is satisfied, in part, within SRP Section 3.9.3 [Ref. 46] if the applicant demonstrates that snubber functionality is maintained under combined SSE and LOCA loads. Further, the applicant must evaluate the LOCA loads for a full spectrum of pipe break locations and sizes, up to and including a double-ended guillotine break of the largest pipe in the plant. The limited analysis of component support failures in NUREG-1903 provides an insufficient basis for either generically revising these SRP requirements or allowing changes to the current support design requirements under the proposed risk-informed revision to 1050.46.

Additionally, NUREG-1903 did not explicitly address the risk associated with several other seismically induced indirect failure modes. Some examples are related to the failure of another pressurized component, such as in the secondary-side systems or the smaller primary pressure boundary piping. Debris, jet impingement, or pipe whip from these failures could possibly lead to subsequent PLP failure. Experience has shown that smaller piping lines or tubing may fail under seismic loading when subjected to seismic interaction phenomena, such as large deformations, impact, or collapse of structures or components on the piping or tubing [Ref. 47]. Because NUREG-1903 addressed none of these failure modes, it provides no technical basis to support generic changes to the seismic design, testing, analysis, qualification, and maintenance requirements for those applicable components and systems under the proposed risk-informed revision to 10 CFR 50.46.

Because of the limited consideration of indirect failures within NUREG-1903, the NRC staff will not generically consider proposed changes to the seismic design, testing, analysis, qualification, and maintenance requirements under the risk-informed revision to 10 CFR 50.46. An applicant can still pursue plant changes that affect seismic design bases and margins established to satisfy 10 CFR 50.46 requirements[9]. In this case, the applicant shall conduct a plant-specific analysis on the effects of the proposed plant change and demonstrate that the risk associated with seismically induced failures is acceptable.

The plant-specific analysis should determine risk contributions from both the direct failure of the altered components or systems and the indirect failure of the PLP. Depending on the proposed plant change, the analysis should consider one or more of the following three potential failure modes:

(1) failure of a support for a component that is attached to the PLP
(2) secondary failure resulting from a component failure that impacts the PLP
(3) failure of single of multiple PLP supports

The plant-specific analysis should incorporate a full-scope PRA to demonstrate that incremental risk associated with the proposed plant change is acceptable. This assessment should also

[9] Proposed plant changes still must satisfy all other seismic requirements governed by regulations other than 10 CFR 50.46. These other regulations are unaffected by any revision of 10 CFR 50.46 requirements.

utilize the site-specific seismic hazard curve, UHS, and the applicable structure, system, and component fragilities as described in Section 4.6 of NUREG-1903.

3 References

[1] *U.S. Code of Federal Regulations, "*Domestic Licensing of Production and Utilization Facilities," Part 50, Title 10.

[2] Tregoning, R.L., Abramson, L.A., and Scott, P., "Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process," NUREG-1829, Vols. 1 and 2, U.S. Nuclear Regulatory Commission, Washington, DC, April 2008.

[3] Chokshi, N.C., Shaukat, S.K., Hiser, A.L., DeGrassi, G., Wilkowski, G., Olson, R., and Johnson, J.J., "Seismic Considerations For the Transition Break Size," NUREG-1903, U.S. Nuclear Regulatory Commission, Washington, DC, February 2008.

[4] Staff Requirement - SECY-07-0082 – Rulemaking to Make Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirement; 10 CFR 50.46a, "Alternative Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors," dated August 10, 2007, Agencywide Documents Access and Management System (ADAMS) Accession No. ML072220595.

[5] *ASME Boiler and Pressure Vessel Code*, 2007 Edition, The American Society of Mechanical Engineers, New York, NY, July 1, 2007.

[6] ASME B31.1-2007, "Power Piping," The American Society of Mechanical Engineers, New York, NY, December 7, 2007.

[7] *U.S. Code of Federal Regulations,* "Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants," Part 52, Title 10.

[8] Generic Letter 88-01, Supplement 1, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," U.S. Nuclear Regulatory Commission, February 4, 1992.

[9] Draft Code Case N-770, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without the Application of Listed Mitigation Activities," Section XI, Division 1, Cases of ASME Boiler and Pressure Vessel Code, Rev X., July 2, 2008.

[10] "Generic Aging Lessons Learned (GALL) Report," NUREG-1801, Vols.1 and 2, Rev. 1, U.S. Nuclear Regulatory Commission, Washington, DC, September 2005.

[11] "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," NUREG-1800, Rev. 1, U.S. Nuclear Regulatory Commission, Washington, DC, September 2005.

[12] Letter from C.I. Grimes (USNRC) to D.J. Walters (NEI), "License Renewal Issue No. 98-0030, 'Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,'" May 19, 2000, ADAMS Accession No. ML003717179.

[13] "BWRVIP-75-A: BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," EPRI Report TR-1012621, Palo Alto, CA, October 2005, ADAMS Accession No. ML053070151.

[14] Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," U.S. Nuclear Regulatory Commission, March 17, 1988, ADAMS Accession No. ML031130424.

[15] Regulatory Issue Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" U.S. Nuclear Regulatory Commission, July 29, 2003, ADAMS Accession No. ML032100653.

[16] Code Case N-722, "Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated With Alloy 600/82/182 Materials," Section XI, Division 1, Cases of ASME Boiler and Pressure Vessel Code, 2007 Edition.

[17] Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds," Section XI, Division 1, Cases of ASME Boiler and Pressure Vessel Code, 2007 Edition.
[18] "Pressurized Water Reactor Primary System Water Chemistry Guidelines," EPRI TR-1002884, Vols. 1 and 2, Rev. 6, Electric Power Research Institute, Palo Alto, CA, 2007.
[19] "Pressurized Water Reactor Secondary Water Chemistry Guidelines—Revision 6," EPRI TR-1008224, Electric Power Research Institute, Palo Alto, CA, 2007, December 2004.
[20] "BWRVIP-130: BWR Vessel and Internals Project BWR Water Chemistry Guidelines—2004 Revision," EPRI TR-1008192, Electric Power Research Institute, Palo Alto, CA, October 2004.
[21] *U.S. Code of Federal Regulations, "*Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Part 54, Title 10.
[22] Regulatory Guide 1.207, "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components due to the Effects of the Light-Water Reactor Environment for New Reactors," Revision 0, U.S. Nuclear Regulatory Commission, Washington, DC, March 2007, ADAMS Accession No. ML070380586.
[23] *U.S. Code of Federal Regulations,* "General Design Criteria for Nuclear Power Plants," Appendix A to Part 50, Title 10.
[24] Kupperman, D.S., Sheen, S.H., Shack, W.J., Diercks, D.R., Krishnaswamny, P., Rudland, D., Wilkowski, G.M., "Barrier Integrity Research Program," NUREG/CR-6861, U.S. Nuclear Regulatory Commission, Washington, DC, February 2004, ADAMS Accession No. ML043580207.
[25] Regulatory Guide 1.45, "Guidance of Monitoring and Responding to Reactor Coolant System Leakage," Rev. 1, U.S. Nuclear Regulatory Commission, Washington, DC, May 2008, ADAMS Accession No. ML073200271.
[26] NUREG-0800, Section 3.6.3, Rev. 1, "Leak-Before-Break Evaluation Procedures," U.S. Nuclear Regulatory Commission, Washington, DC, March 2007, ADAMS Accession No. ML063600396.
[27] "Review Standard for Extended Power Uprates," RS-001, Rev. 0, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, DC, December 2003, ADAMS Accession No. ML033640024.
[28] Memorandum from A.T. Howell, III (Team Leader) to W.F. Kane (DEDORP), "Degradation of the Davis-Besse Nuclear Power Station Reactor Pressure Vessel Head Lessons Learned Report," September 30, 2002, ADAMS Accession No. ML022760414.
[29] Regulatory Issue Summary 2006-13, "Information on the Changes Made to the Reactor Oversight Process to More Fully Address Safety Culture," U.S. Nuclear Regulatory Commission, Office of Enforcement, Washington, DC, July 31, 2006, ADAMS Accession No. ML061880341.
[30] "Individual Plant Examination of External Events (IPEEE) Seismic Insights," revision to EPRI Report TR-112932, Electric Power Research Institute, Palo Alto, CA, 2000.
[31] Reed, J.W. and Kennedy, R.P., "Methodology for Developing Seismic Fragilities," EPRI Report TR-103959, Electric Power Research Institute, Palo Alto, CA, 1994.
[32] Sobel, P., "Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains," NUREG-1488, U.S. Nuclear Regulatory Commission, Washington, DC, April 1994.
[33] "American National Standard—External Events PRA Methodology," ANSI/ANS 58-21-2007, American Nuclear Society, La Grange Park, IL, 2007.

[34] “Evaluation of Flaws in Austenitic Steel Piping,” prepared by Section XI Task Group for Piping Flaw Evaluation, EPRI Report NP-4690-SR, Electric Power Research Institute, Palo Alto, CA, April 1986.
[35] “Probability of Pipe Failure in the Reactor Coolant Loops of Westinghouse PWR Plants,” NUREG/CR-3660, Vols. 1–4, U.S. Nuclear Regulatory Commission, Washington, DC, 1985.
[36] “Probability of Pipe Failure in the Reactor Coolant Loops of Combustion Engineering PWR Plants,” NUREG/CR-3663, Vols. 1–3, U.S. Nuclear Regulatory Commission, Washington, DC, 1985.
[37] “Probability of Pipe Failure in the Reactor Coolant Loops of Babcock and Wilcox PWR Plants,” NUREG/CR-4290, Vols. 1–3, U.S. Nuclear Regulatory Commission, Washington, DC, 1985.
[38] “Probability of Failure in BWR Reactor Coolant Piping,” NUREG/CR-4792, Vols. 1–4, U.S. Nuclear Regulatory Commission, Washington, DC, 1988.
[39] Ghadiali, N., and Wilkowski, G.M., “Fracture Mechanics Database for Nuclear Piping Materials (PIFRAC),” in *Fatigue and Fracture*, Vol. 2, PVP-Vol. 324, pp. 77–84, American Society of Mechanical Engineers, New York, NY, July 1996.
[40] Wilkowski, G.M., Olson, R.J., and Scott, P.M., “State-of-the-Art Report on Piping Fracture Mechanics,” NUREG/CR-6540, U.S. Nuclear Regulatory Commission, Washington, DC, February 1998.
[41] Gavenda, D.J., Michuard, W.F., Galvin, T.M., Burke, W.F., and Chopra, O.K., “Effect of Thermal Aging on Fracture Toughness and Charpy-Impact Strength of Stainless Steel Pipe Welds,” NUREG/CR-6428, May 1996.
[42] Code Case N-740-1, “Dissimilar Metal Weld Overlay for Repair or Mitigation of Class 1, 2 and 3 Items,” Section XI, Division 1, Cases of ASME Boiler and Pressure Vessel Code, 2007, January 4, 2008.
[43] King, C., “Non-Proprietary Version, Materials Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline (MRP-139NP),” EPRI Report Number 1010087, Electric Power Research Institute, Palo Alto, CA, 2005.
[44] Hazelton, W.S., “Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping,” NUREG-0313, Division of BWR Licensing, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington DC, 1986.
[45] Section 3.9.2, Rev. 3, “Dynamic Testing and Analysis of Systems, Structures, and Components,” NUREG-0800, Rev. 1, U.S. Nuclear Regulatory Commission, Washington, DC, March 2007, ADAMS Accession No. ML063600396.
[46] Section 3.9.3, Rev. 2, “ASME Code Class 1, 2, and 3 Components, and Component Supports, and Core Support Structures,” NUREG-0800, Rev. 1, U.S. Nuclear Regulatory Commission, Washington, DC, March 2007, ADAMS Accession No. ML063600396.
[47] Stevenson, J.D., “Survey of Strong Motion Earthquake Effects on Thermal Power Plants in California with Emphasis on Piping Systems,” Main Report, Vol. 1, NUREG/CR-6239, U.S. Nuclear Regulatory Commission, Washington, DC, November 1995.

Appendix A

Detailed Information for Analyses Conducted in NUREG-1903

This appendix contains information used in performing the seismic analyses in NUREG-1903. The plant names are coded and the codes have been changed for each unique table. Licensees can contact the NRC for the plant-specific code identifiers.

The key tables consist of the following:

Table A-1 List of the 26 plants evaluated in NUREG-1903.

Table A-2 Scale factors, original design SSE PGA values, Weibull fit coefficients to mean PGA probability curves, and calculated PGA values at seismic event with probability of 10E-6

Table A-3 PWR coolant piping information and calculated values by plant , i.e.,

- Plant code number
- Segment of primary pipe loop used in evaluation, i.e., hot-leg, cold-leg, etc.
- Pipe dimensions,
- Materials at hypothetical crack location (base metal and weld metals),
- Yield, ultimate, and flow stress using ASME Code values and mean or typical best estimate (BE) values from actual piping material data,
- Elastic-plastic toughness correction factors (Z-factors) using both;
    - ASME Section XI Code values, and
    - updated values from BE EPFM analyses to account for dynamic and cyclic corrections,
- Normal operating temperature, pressure, and dead-weight and thermal expansion stresses,
- Design SSE stresses,
- Calculated elastic stresses for 10E-6 seismic event (linearly scaled from seismic hazard curves),
- Scaling factor on original seismic design, i.e., accounts for conservatisms in original seismic analyses compared to current state-of-the-art seismic analyses,
- Calculated elastic stresses for 10E-6 seismic event with scaling factor correction,
- 10E-6 stresses with additional nonlinear stress correction factor, and
- Calculated surface-crack depths as a function of crack length at N+10E-6 corrected seismic stress using;
    - ASME Code analysis with code strengths,
    - ASME Code analysis with typical actual strengths, and
    - BE analysis.

Table A-1 List of the 26 plants evaluated in NUREG-1903

Arkansas 2
Beaver Valley 1
Braidwood 1
Braidwood 2
Byron 1
Byron 2
Callaway
Calvert Cliffs 1
Catawba 1
Catawba 2
Farley 1
Farley 2
Indian Point 2
McGuire 1
McGuire 2
Millstone 2
Millstone 3
Prairie Island 1
Seabrook 1
Sequoyah 1
Sequoyah 2
Shearon Harris 1
Turkey Point 3
Turkey Point 4
Watts Bar 1
Wolf Creek

Table A-2 Scale factors, original design SSE PGA values, Weibull fit coefficients to mean PGA probability curves, and calculated PGA values at seismic event with probability of 10E-6

Site Identification Code	Original design SSE, g	Weibul fit parameters for mean PGA probability curves			SSE probability	PGA at 10^{-6}, g	Ratio of PGA to original SSE value 10^{-6} / 1SSE
		scale	alpha	beta			
A	0.153	0.047	0.430	13.890	2.32E-05	0.633	4.135
B	0.100	0.062	0.384	12.300	5.85E-05	0.826	8.263
C	0.100	0.063	0.410	11.200	5.58E-05	0.675	6.754
D	0.100	0.068	0.395	12.280	6.37E-05	0.799	7.990
E	0.120	0.076	0.405	7.494	3.78E-05	0.574	4.785
F	0.100	0.081	0.424	11.340	7.24E-05	0.692	6.922
G	0.120	0.095	0.364	3.792	3.10E-05	0.526	4.384
H	0.104	0.098	0.391	15.270	9.65E-05	1.080	10.380
I	0.100	0.107	0.359	6.193	7.09E-05	0.780	7.798
J	0.120	0.120	0.389	18.130	1.04E-04	1.313	10.946
K	0.100	0.126	0.384	10.690	1.11E-04	0.991	9.914
L	0.104	0.127	0.379	15.100	1.24E-04	1.271	12.221
M	0.120	0.128	0.377	12.780	9.39E-05	1.165	9.709
N	0.120	0.130	0.380	13.050	9.63E-05	1.165	9.711
O	0.120	0.138	0.387	16.640	1.15E-04	1.327	11.062
P	0.200	0.154	0.470	16.560	4.85E-05	0.851	4.257
Q	0.240	0.163	0.423	9.204	2.24E-05	0.753	3.136
R	0.200	0.169	0.444	11.860	4.11E-05	0.799	3.993
S	0.153	0.175	0.441	12.280	7.62E-05	0.843	5.510
T	0.120	0.180	0.397	5.913	7.52E-05	0.685	5.711
U	0.200	0.181	0.462	15.200	5.34E-05	0.876	4.380
V	0.153	0.206	0.343	4.465	5.57E-05	0.922	6.024
W	0.153	0.232	0.447	11.240	9.12E-05	0.825	5.392
X	0.170	0.258	0.399	17.740	1.31E-04	1.600	9.411
Y	0.170	0.279	0.434	34.670	1.99E-04	2.071	12.181
Z	0.153	0.293	0.373	8.107	1.11E-04	1.193	7.799
AA	0.200	0.295	0.299	2.698	4.43E-05	1.196	5.979
AB	0.200	0.306	0.451	14.290	8.81E-05	1.032	5.161
AC	0.100	0.309	0.452	14.110	3.10E-04	1.022	10.222
AD	0.200	0.338	0.317	3.634	5.62E-05	1.248	6.239
AE	0.120	0.358	0.467	17.230	3.00E-04	1.122	9.351
AF	0.150	0.373	0.365	8.262	1.52E-04	1.403	9.355
AG	0.170	0.374	0.443	13.930	1.48E-04	1.129	6.644
AH	0.120	0.377	0.485	18.180	3.24E-04	1.062	8.853
AI	0.200	0.378	0.364	9.629	1.05E-04	1.564	7.819
AJ	0.200	0.384	0.423	28.750	1.96E-04	2.150	10.752
AK	0.170	0.391	0.379	9.503	1.36E-04	1.387	8.158
AL	0.230	0.397	0.452	15.550	9.35E-05	1.174	5.104
AM	0.170	0.402	0.448	15.290	1.70E-04	1.189	6.997
AN	0.153	0.432	0.456	15.920	2.26E-04	1.188	7.765
AO	0.153	0.435	0.441	13.840	2.09E-04	1.186	7.752
AP	0.180	0.438	0.458	15.170	1.61E-04	1.142	6.342
AQ	0.200	0.440	0.412	18.870	1.76E-04	1.803	9.017

Note; In NUREG-1903 (and above table), the probability of occurrence is P(x) and $P(x) = Scale \cdot \alpha \cdot \beta^{-\alpha} x^{\alpha-1} e^{-(x/\beta)^{\alpha}}$ where x is the PGA amplitude in cm/s^2.

Table A-2 Scale factors, original design SSE PGA values, Weibull fit coefficients to mean PGA probability curves, and calculated PGA values at seismic event with probability of 10E-6, continued

Site Identification Code	Original design SSE, g	Weibul fit parameters for mean PGA probability curves			SSE probability	PGA at 10^{-6}, g	Ratio of PGA to original SSE value 10^{-6} / 1SSE
		scale	alpha	beta			
AR	0.180	0.440	0.461	15.880	1.68E-04	1.158	6.434
AS	0.180	0.460	0.464	16.300	1.78E-04	1.172	6.512
AT	0.120	0.467	0.340	6.694	2.53E-04	1.650	13.754
AU	0.200	0.472	0.369	8.041	1.12E-04	1.435	7.175
AV	0.200	0.478	0.369	8.086	1.14E-04	1.446	7.231
AW	0.100	0.520	0.435	11.150	4.53E-04	1.105	11.051
AX	0.153	0.530	0.416	7.490	1.58E-04	0.961	6.280
AY	0.153	0.546	0.342	2.249	7.78E-05	0.815	5.325
AZ	0.200	0.564	0.378	4.609	7.24E-05	0.950	4.752
BA	0.150	0.589	0.406	7.511	1.92E-04	1.072	7.149
BB	0.153	0.594	0.398	6.154	1.59E-04	0.997	6.518
BC	0.153	0.612	0.288	1.422	9.82E-05	1.212	7.924
BD	0.100	0.624	0.399	8.438	4.72E-04	1.251	12.514
BE	0.200	0.631	0.392	7.301	1.21E-04	1.198	5.992
BF	0.140	0.755	0.373	5.197	2.35E-04	1.186	8.469
BG	0.255	0.772	0.470	19.000	1.70E-04	1.440	5.647
BH	0.153	0.910	0.319	1.234	8.84E-05	0.840	5.488
BI	0.153	0.923	0.319	1.223	8.84E-05	0.836	5.464
BJ	0.153	0.930	0.425	29.320	7.13E-04	2.819	18.427
BK	0.153	1.105	0.373	5.046	2.81E-04	1.289	8.423
BL	0.200	1.239	0.370	10.030	3.48E-04	2.236	11.178
BM	0.255	1.344	0.302	1.998	9.47E-05	1.645	6.450
BN	0.100	1.414	0.328	4.706	8.55E-04	2.155	21.549
BO	0.200	2.299	0.301	1.873	2.48E-04	1.906	9.528
BP	0.160	2.592	0.241	0.355	2.25E-04	1.899	11.867
BQ	0.200	4.543	0.267	0.159	5.15E-05	0.783	3.917

Note; In NUREG-1903 (and above table), the probability of occurrence is P(x) and $P(x) = Scale \cdot \alpha \cdot \beta^{-\alpha} x^{\alpha-1} e^{-(x/\beta)^{\alpha}}$ where x is the PGA amplitude in cm/s^2.

Table A-3a PWR coolant piping information and calculated values by plant – Pipe sizes, material properties, and Z-factors

Plant identification code	Pipe leg	Inside Diameter, inch	Pipe Thickness, inch	Materials	ASME Code Z-factor			Best-estimate Z-factor	
					Crack location	ASME Z-factor equation	Z-factor	Crack location	Z-factor
i	Hot Leg	29.20	2.370	SS SAW	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.638	New SS SAW	1.647
ii	Cross-over	30.26	2.560	SS SAW	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.641	New SS SAW	1.645
iii	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.644
iii	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.642
iii	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.646
iv	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.644
iv	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.642
iv	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.646
v	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.644
v	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.642
v	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.646
vi	Hot leg	29.00	2.450	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.644
vi	Cold leg	27.50	2.320	SA 376 304N Wrought 304 Pipe	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.642
vi	Crossover leg	31.00	2.600	SA351 CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.646
vii	Hot leg	29.20	2.370	SA351-CF8A, stainless steel weld	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.647
viii	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.649
ix	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.649
x	Hot leg	29.22	2.280	SA351 CF8A with SMAW and SAW welds	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.650
xi	Hot leg	29.22	2.280	SA351 CF8A with SMAW and SAW welds	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.650
xii	Hot leg	29.20	2.690	Pipe is wrought TP316 and fittings are CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.636
xii	Crossover leg	27.70	2.550	Pipe is wrought TP316 and fittings are CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.608	New SS SAW	1.635
xii	Cold leg	31.20	2.880	Pipe is wrought TP316 and fittings are CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.654	New SS SAW	1.637
xiii	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.649
xiv	Hot leg	29.20	2.310	CF8A pipe and CF8M fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.649
xv	Hot leg	29.20	2.690	SA-351-CF8M for fittings and wrought 316 for straight pipe.	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.636
xvi	Hot leg	29.20	2.370	SA-376 304N, Wrought stainless steel pipe; SA-351-CF8A, cast stainless steel fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.647
xvii	Hot leg	29.00	2.700	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.635
xvii	Cold leg	27.50	2.560	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.633
xvii	Crossover leg	31.00	2.880	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.637
xviii	Hot leg	29.00	2.700	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.625	New SS SAW	1.635
xviii	Cold leg	27.50	2.560	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.606	New SS SAW	1.633
xviii	Crossover leg	31.00	2.880	SA351 CF8M	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.651	New SS SAW	1.637

Source for strength values	Material	Yield stress, psi	Ultimate stress, psi	Flow stress, psi
From ASME code	CF8M	21,200	65,200	43,200
From ASME code	A516Gr70	27,600	70,000	48,800
Typical actual value	CF8M	29,160	76,750	52,955
Typical actual value	A516Gr70	34,050	71,620	52,835

S_m table, ksi					
Material	@ 500 F	@ 600 F	@ 650 F	@ 550 F	@ 620 F
CF8	20.50	19.30	18.90	19.90	19.14
A516	20.50	18.70	18.40	19.60	18.58

Table A-3a PWR coolant piping information and calculated values by plant in NUREG-1903 – Pipe sizes, material properties, and Z-factors, continued

Plant identification code	Pipe leg	Inside Diameter, inch	Pipe Thickness, inch	Materials	ASME Code Z-factor			Best-estimate Z-factor	
					Crack location	ASME Z-factor equation	Z-factor	Crack location	Z-factor
xix	Hot leg	29.20	2.370	SA-376-TP304N, SA-351-CF8A, Cast stainless steel fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.647
xx	Hot leg	29.21	2.395	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.646
xx	Cold leg	27.71	2.270	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.608	New SS SAW	1.645
xx	Crossover leg	31.21	3.208	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.654	New SS SAW	1.627
xxi	Hot leg	29.21	2.395	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.646
xxi	Cold leg	27.71	2.270	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.608	New SS SAW	1.645
xxi	Crossover leg	31.21	3.208	A376 TP316 for loop pipe and A351-CF8M for the elbow fittings	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.654	New SS SAW	1.627
xxii	Hot leg	29.11	2.340	SA-351-CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.626	New SS SAW	1.648
xxii	Cold leg	27.71	2.210	SA-351-CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.608	New SS SAW	1.647
xxii	Crossover leg	31.22	2.480	SA-351-CF8A	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.654	New SS SAW	1.651
xxiii	Hot leg	29.20	2.370	SA351-CF8A, stainless steel weld	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.628	New SS SAW	1.647
xxiv	Hot-leg	42.00	3.750	A516 Gr 70	Ferritic base	Z=1.2*(1+0.021*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	2.010	New ferritic base	1.394
xxiv	Hot-leg	42.00	3.750	Ferritic SAW	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	2.149	New ferritic weld	1.229
xxiv	Cold-leg - suction	30.00	2.500	A516 Gr 70	Ferritic base	Z=1.2*(1+0.021*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.767	New ferritic base	1.396
xxiv	Cold-leg - suction	30.00	2.500	Ferritic SAW	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.909	New ferritic weld	1.228
xxiv	Cold-leg - suction	30.00	2.500	SS SAW	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.638	New SS SAW	1.419
xxiv	Cold-leg - discharge	30.00	2.500	A516 Gr 70	Ferritic base	Z=1.2*(1+0.021*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.767	New ferritic base	1.396
xxiv	Cold-leg - discharge	30.00	2.500	Ferritic SAW	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.909	New ferritic weld	1.228
xxiv	Cold-leg - discharge	30.00	2.500	SS SAW	SS SAW	Z=1.3*(1+0.01*(NPS-4))	1.638	New SS SAW	1.419
xxv	Hot leg	42.00	3.750	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	2.149	New ferritic weld	1.229
xxv	Cold leg - suction	30.00	2.500	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.909	New ferritic weld	1.228
xxv	Cold leg - discharge	30.00	3.000	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.875	New ferritic weld	1.211
xxvi	Hot leg	42.00	3.750	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	2.149	New ferritic weld	1.229
xxvi	Cold leg - suction	30.00	2.500	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.909	New ferritic weld	1.228
xxvi	Cold leg - discharge	30.00	2.500	SA-516-70	Ferritic SAW	Z=1.35*(1+0.0184*A*(NPS-4)) A=(0.125*(Rm/t)-0.25)^0.25	1.875	New ferritic weld	1.211

Source for strength values	Material	Yield stress, psi	Ultimate stress, psi	Flow stress, psi
From ASME code	CF8M	21,200	65,200	43,200
From ASME code	A516Gr70	27,600	70,000	48,800
Typical actual value	CF8M	29,160	76,750	52,955
Typical actual value	A516Gr70	34,050	71,620	52,835

S_m table, ksi					
Material	@ 500 F	@ 600 F	@ 650 F	@ 550 F	@ 620 F
CF8	20.50	19.30	18.90	19.90	19.14
A516	20.50	18.70	18.40	19.60	18.58

Table A-3b PWR coolant piping information and calculated values by plant in NUREG-1903 – Normal operating stresses, SSE stresses, and 10E-6 stresses without and with correction factors

Plant identification code	Pipe leg	Normal Operating Temperature, F	Normal operating Pressure, psig	Thermal expansion stress, ksi	Normal operating stress with pressure and thermal expansion, ksi	SSE stress at worst location, ksi	N+1SSE stress, ksi	10E-6 seismic stress - linear extrapolated, ksi	N+10E-6 seismic stress - linearly extrapolated, ksi	Seismic Scaling Factor	N+10E-6 stress with seismic scale factor, ksi	N+10E-6 stress with seismic scale factor and elastic stress correction, ksi
i	Hot Leg	617	2,235	0.51	9.87	15.36	25.23	102.06	111.93	0.485	59.37	34.61
ii	Cross-over	547	2,200	0.52	9.56	8.36	17.92	114.95	124.51	0.230	36.00	30.39
iii	Hot leg	617	2,250	7.02	16.15	12.96	29.12	51.76	67.92	0.510	42.54	31.57
iii	Cold leg	557	2,305	0.69	10.08	21.45	31.53	85.64	95.72	0.510	53.73	33.59
iii	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	37.18	45.38	0.510	27.15	27.15
iv	Hot leg	617	2,250	7.02	16.15	12.96	29.12	51.76	67.92	0.510	42.54	31.57
iv	Cold leg	557	2,305	0.69	10.08	21.45	31.53	85.64	95.72	0.510	53.73	33.59
iv	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	37.18	45.38	0.510	27.15	27.15
v	Hot leg	617	2,250	7.02	16.15	12.96	29.12	56.77	72.93	0.528	46.13	32.22
v	Cold leg	557	2,305	0.69	10.08	21.45	31.53	93.93	104.01	0.528	59.68	34.66
v	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	40.78	48.98	0.528	29.73	29.26
vi	Hot leg	617	2,250	7.02	16.15	12.96	29.12	56.77	72.93	0.528	46.13	32.22
vi	Cold leg	557	2,305	0.69	10.08	21.45	31.53	93.93	104.01	0.528	59.68	34.66
vi	Crossover leg	557	2,215	0.00	8.19	9.31	17.51	40.78	48.98	0.528	29.73	29.26
vii	Hot leg	617	2,235	12.21	21.57	7.31	28.87	28.62	50.19	0.588	38.38	30.82
viii	Hot leg	618	2,235	9.39	18.93	7.81	26.73	55.81	74.73	0.673	56.51	34.09
ix	Hot leg	618	2,235	9.39	18.93	7.81	26.73	55.81	74.73	0.673	56.51	34.09
x	Hot leg	611	2,235	11.93	21.56	4.36	25.93	30.21	51.77	0.718	43.25	31.70
xi	Hot leg	611	2,235	11.93	21.56	4.36	25.93	30.21	51.77	0.718	43.25	31.70
xii	Hot leg	613	2,235	12.96	21.50	4.56	26.06	35.37	56.87	0.756	48.24	32.60
xii	Crossover leg	555	2,235	0.00	7.34	8.43	15.77	65.32	72.66	0.756	56.72	34.13
xii	Cold leg	555	2,235	12.29	20.89	4.42	25.31	34.28	55.17	0.756	46.81	32.34
xiii	Hot leg	618	2,235	9.39	18.93	7.81	26.73	49.03	67.95	0.591	47.92	32.54
xiv	Hot leg	618	2,235	9.39	18.93	7.81	26.73	49.03	67.95	0.591	47.92	32.54
xv	Hot leg	599	2,235	8.52	17.13	3.13	20.27	34.27	51.40	0.828	45.50	32.11
xvi	Hot leg	617	2,235	15.37	24.72	6.54	31.27	36.96	61.68	0.472	42.17	31.50
xvii	Hot leg	613	2,235	10.98	19.46	1.44	20.89	9.36	28.82	0.979	28.62	28.62
xvii	Cold leg	555	2,290	0.00	8.23	8.35	16.58	54.38	62.61	0.979	61.47	34.98
xvii	Crossover leg	555	2,200	3.40	11.86	4.18	16.04	27.23	39.09	0.979	38.51	30.85
xviii	Hot leg	613	2,235	10.98	19.46	1.44	20.89	9.36	28.82	0.979	28.62	28.62
xviii	Cold leg	555	2,290	0.00	8.23	8.35	16.58	54.38	62.61	0.979	61.47	34.98
xviii	Crossover leg	555	2,200	3.40	11.86	4.18	16.04	27.23	39.09	0.979	38.51	30.85

Table A-3b PWR coolant piping information and calculated values by plant in NUREG-1903 – Normal operating stresses, SSE stresses, and 10E-6 stresses without and with correction factors, continued

Plant identification code	Pipe leg	Normal Operating Temperature, F	Normal operating Pressure, psig	Thermal expansion stress, ksi	Normal operating stress with pressure and thermal expansion, ksi	SSE stress at worst location, ksi	N+1SSE stress, ksi	10E-6 seismic stress - linear extrapolated, ksi	N+10E-6 seismic stress - linearly extrapolated, ksi	Seismic Scaling Factor	N+10E-6 stress <u>with</u> seismic scale factor, ksi	N+10E-6 stress <u>with</u> seismic scale factor <u>and</u> elastic stress correction, psi
xix	Hot leg	619	2,235	14.29	23.65	3.03	26.68	16.35	39.99	0.549	32.62	29.78
xx	Hot leg	608	2,250	9.65	18.99	2.58	21.57	10.67	29.66	0.764	27.15	27.15
xx	Cold leg	547	2,250	1.54	10.95	2.16	13.11	8.93	19.89	0.764	17.78	17.78
xx	Crossover leg	547	2,250	0.41	8.44	0.73	9.17	3.02	11.46	0.764	10.75	10.75
xxi	Hot leg	608	2,250	9.65	18.99	2.58	21.57	10.67	29.66	0.764	27.15	27.15
xxi	Cold leg	547	2,250	1.54	10.95	2.16	13.11	8.93	19.89	0.764	17.78	17.78
xxi	Crossover leg	547	2,250	0.41	8.44	0.73	9.17	3.02	11.46	0.764	10.75	10.75
xxii	Hot leg	618	2,250	10.31	19.78	5.87	25.65	37.75	57.53	0.563	41.03	31.30
xxii	Cold leg	558	2,305	4.27	14.06	11.73	25.80	75.49	89.55	0.563	56.55	34.10
xxii	Crossover leg	558	2,250	0.00	7.80	8.65	16.45	55.62	63.42	0.563	39.11	30.95
xxiii	Hot leg	617	2,235	12.21	21.57	7.31	28.87	41.73	63.30	0.549	44.48	31.92
xxiv	Hot-leg	650	2,250	12.27	21.72	3.23	24.94	30.17	44.47	0.480	36.20	30.43
xxiv	Hot-leg	650	2,250	0.00	21.72	3.23	24.94	30.17	44.47	0.480	36.20	30.43
xxiv	Cold-leg - suction	550	2,250	13.00	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold-leg - suction	550	2,250	13.00	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold-leg - suction	550	2,250	0.35	9.63	6.88	16.50	64.33	66.08	0.480	40.51	31.21
xxiv	Cold-leg - discharge	550	2,250	0.35	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxiv	Cold-leg - discharge	550	2,250	0.35	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxiv	Cold-leg - discharge	550	2,250	1.15	10.42	8.88	19.30	83.06	85.60	0.480	50.29	32.97
xxv	Hot leg	650	2,250	1.15	19.69	1.21	20.90	7.24	19.51	1.077	27.49	27.49
xxv	Cold leg - suction	550	2,250	1.15	10.02	4.47	14.50	26.81	28.96	1.077	38.90	30.92
xxv	Cold leg - discharge	550	2,250	10.87	8.39	7.67	16.06	45.95	47.59	1.077	57.89	34.34
xxvi	Hot leg	650	2,250	0.75	18.45	2.60	21.05	17.25	28.27	0.591	28.65	28.65
xxvi	Cold leg - suction	550	2,250	0.24	11.38	5.67	17.05	37.68	41.18	0.591	33.66	29.97
xxvi	Cold leg - discharge	550	2,250	9.63	9.53	9.30	18.83	61.79	63.44	0.591	46.07	32.21

Table A-3c PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using ASME Code strength assumption

Plant identification code	Pipe leg	Crack depth a/t by ASME Code procedure (using Code strengths) as a function of crack length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
i	Hot Leg	0.317	0.164	0.117	0.110	0.108	0.106	0.104	0.103	0.103	0.102
ii	Cross-over	0.750	0.750	0.617	0.499	0.440	0.411	0.401	0.401	0.401	0.401
iii	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
iii	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iii	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
iv	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
iv	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iv	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
v	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
v	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
v	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
vi	Hot leg	0.148	0.123	0.115	0.110	0.107	0.105	0.104	0.103	0.102	0.102
vi	Cold leg	0.146	0.123	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
vi	Crossover leg	0.750	0.750	0.628	0.508	0.447	0.417	0.407	0.406	0.406	0.406
vii	Hot leg	0.289	0.150	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
viii	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
ix	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
x	Hot leg	0.750	0.446	0.315	0.257	0.228	0.217	0.215	0.215	0.215	0.215
xi	Hot leg	0.750	0.446	0.315	0.257	0.228	0.217	0.215	0.215	0.215	0.215
xii	Hot leg	0.750	0.448	0.317	0.259	0.231	0.220	0.219	0.219	0.219	0.219
xii	Crossover leg	0.750	0.750	0.750	0.617	0.541	0.503	0.488	0.486	0.486	0.486
xii	Cold leg	0.750	0.468	0.332	0.271	0.242	0.230	0.228	0.228	0.228	0.228
xiii	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
xiv	Hot leg	0.562	0.292	0.207	0.169	0.151	0.145	0.144	0.144	0.144	0.144
xv	Hot leg	0.750	0.750	0.622	0.504	0.444	0.416	0.406	0.405	0.405	0.405
xvi	Hot leg	0.145	0.122	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
xvii	Hot leg	0.750	0.750	0.629	0.509	0.449	0.420	0.410	0.410	0.410	0.410
xvii	Cold leg	0.750	0.750	0.716	0.578	0.508	0.473	0.460	0.458	0.458	0.458
xvii	Crossover leg	0.750	0.750	0.750	0.632	0.554	0.515	0.499	0.496	0.496	0.496
xviii	Hot leg	0.750	0.750	0.629	0.509	0.449	0.420	0.410	0.410	0.410	0.410
xviii	Cold leg	0.750	0.750	0.716	0.578	0.508	0.473	0.460	0.458	0.458	0.458
xviii	Crossover leg	0.750	0.750	0.750	0.632	0.554	0.515	0.499	0.496	0.496	0.496

Table A-3c PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using ASME Code strength assumption, continued

Plant identification code	Pipe leg	Crack depth a/t by ASME Code procedure (using Code strengths) as a function of crack length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
xix	Hot leg	0.750	0.435	0.308	0.251	0.223	0.212	0.211	0.211	0.211	0.211
xx	Hot leg	0.750	0.750	0.560	0.454	0.400	0.375	0.366	0.366	0.366	0.366
xx	Cold leg	0.750	0.750	0.750	0.750	0.661	0.610	0.586	0.578	0.578	0.578
xx	Crossover leg	0.750	0.750	0.750	0.750	0.750	0.735	0.703	0.690	0.688	0.688
xxi	Hot leg	0.750	0.750	0.560	0.454	0.400	0.375	0.366	0.366	0.366	0.366
xxi	Cold leg	0.750	0.750	0.750	0.750	0.661	0.610	0.586	0.578	0.578	0.578
xxi	Crossover leg	0.750	0.750	0.750	0.750	0.750	0.735	0.703	0.690	0.688	0.688
xxii	Hot leg	0.750	0.427	0.302	0.247	0.220	0.208	0.207	0.207	0.207	0.207
xxii	Cold leg	0.522	0.271	0.192	0.157	0.140	0.134	0.134	0.134	0.134	0.134
xxii	Crossover leg	0.750	0.750	0.693	0.559	0.491	0.456	0.442	0.441	0.441	0.441
xxiii	Hot leg	0.289	0.150	0.115	0.110	0.108	0.106	0.104	0.103	0.103	0.102
xxiv	Hot-leg	0.630	0.327	0.232	0.190	0.171	0.164	0.164	0.164	0.164	0.164
xxiv	Hot-leg	0.125	0.125	0.125	0.125	0.125	0.088	0.076	0.072	0.068	0.066
xxiv	Cold-leg - suction	0.750	0.750	0.750	0.750	0.676	0.624	0.600	0.593	0.593	0.593
xxiv	Cold-leg - suction	0.750	0.750	0.750	0.728	0.636	0.589	0.567	0.562	0.562	0.562
xxiv	Cold-leg - suction	0.750	0.750	0.750	0.664	0.582	0.540	0.522	0.519	0.519	0.519
xxiv	Cold-leg - discharge	0.750	0.750	0.582	0.472	0.417	0.391	0.383	0.383	0.383	0.383
xxiv	Cold-leg - discharge	0.750	0.685	0.484	0.393	0.348	0.328	0.324	0.324	0.324	0.324
xxiv	Cold-leg - discharge	0.750	0.750	0.682	0.551	0.485	0.453	0.441	0.440	0.440	0.440
xxv	Hot leg	0.506	0.263	0.187	0.154	0.138	0.133	0.133	0.133	0.133	0.133
xxv	Cold leg - suction	0.750	0.750	0.750	0.659	0.578	0.536	0.519	0.515	0.515	0.515
xxv	Cold leg - discharge	0.750	0.750	0.750	0.735	0.644	0.597	0.576	0.571	0.571	0.571
xxvi	Hot leg	0.443	0.230	0.164	0.135	0.125	0.118	0.118	0.118	0.118	0.118
xxvi	Cold leg - suction	0.750	0.750	0.635	0.514	0.453	0.424	0.414	0.413	0.413	0.413
xxvi	Cold leg - discharge	0.750	0.750	0.713	0.576	0.507	0.472	0.459	0.458	0.458	0.458

Table A-3d PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using ASME Code with typical actual strength assumption

Plant identification code	Pipe leg	Crack depth a/t by ASME Code procedure (using typical actual strengths) as a function of crack length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
i	Hot Leg	0.750	0.616	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
ii	Cross-over	0.750	0.750	0.750	0.666	0.584	0.543	0.526	0.523	0.523	0.523
iii	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
iii	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iii	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
iv	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
iv	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
iv	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
v	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
v	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
v	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
vi	Hot leg		0.464	0.329	0.269	0.241	0.230	0.229	0.229	0.229	0.229
vi	Cold leg		0.135	0.116	0.111	0.108	0.106	0.105	0.104	0.103	0.103
vi	Crossover leg		0.750	0.750	0.672	0.589	0.548	0.530	0.527	0.527	0.527
vii	Hot leg		0.605	0.428	0.349	0.310	0.294	0.291	0.291	0.291	0.291
viii	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
ix	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
x	Hot leg		0.750	0.586	0.476	0.420	0.394	0.386	0.386	0.386	0.386
xi	Hot leg		0.750	0.586	0.476	0.420	0.394	0.386	0.386	0.386	0.386
xii	Hot leg		0.750	0.592	0.481	0.425	0.400	0.393	0.393	0.393	0.393
xii	Crossover leg		0.750	0.750	0.750	0.664	0.615	0.593	0.588	0.588	0.588
xii	Cold leg		0.750	0.603	0.490	0.433	0.407	0.400	0.400	0.400	0.400
xiii	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
xiv	Hot leg		0.713	0.503	0.409	0.363	0.342	0.337	0.337	0.337	0.337
xv	Hot leg		0.750	0.750	0.670	0.588	0.547	0.530	0.528	0.528	0.528
xvi	Hot leg		0.483	0.342	0.280	0.250	0.238	0.237	0.237	0.237	0.237
xvii	Hot leg		0.750	0.750	0.674	0.592	0.551	0.533	0.531	0.531	0.531
xvii	Cold leg		0.750	0.750	0.729	0.638	0.592	0.572	0.567	0.567	0.567
xvii	Crossover leg		0.750	0.750	0.750	0.675	0.625	0.602	0.597	0.597	0.597
xviii	Hot leg		0.750	0.750	0.674	0.592	0.551	0.533	0.531	0.531	0.531
xviii	Cold leg		0.750	0.750	0.729	0.638	0.592	0.572	0.567	0.567	0.567
xviii	Crossover leg		0.750	0.750	0.750	0.675	0.625	0.602	0.597	0.597	0.597

Table A-3d PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using ASME Code with typical actual strength assumption, continued

Plant identification code	Pipe leg	Crack depth a/t by ASME (using typical actual strengths) as a function of crck length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
xix	Hot leg		0.750	0.582	0.472	0.417	0.392	0.384	0.384	0.384	0.384
xx	Hot leg		0.750	0.750	0.629	0.553	0.514	0.499	0.497	0.497	0.497
xx	Cold leg		0.750	0.750	0.750	0.750	0.700	0.670	0.659	0.658	0.658
xx	Crossover leg		0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.747	0.747
xxi	Hot leg		0.750	0.750	0.629	0.553	0.514	0.499	0.497	0.497	0.497
xxi	Cold leg		0.750	0.750	0.750	0.750	0.700	0.670	0.659	0.658	0.658
xxi	Crossover leg		0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.747	0.747
xxii	Hot leg		0.750	0.577	0.468	0.414	0.389	0.381	0.381	0.381	0.381
xxii	Cold leg		0.695	0.491	0.399	0.354	0.334	0.329	0.329	0.329	0.329
xxii	Crossover leg		0.750	0.750	0.712	0.623	0.577	0.557	0.552	0.552	0.552
xxiii	Hot leg		0.605	0.428	0.349	0.310	0.294	0.291	0.291	0.291	0.291
xxiv	Hot-leg		0.504	0.357	0.292	0.261	0.249	0.248	0.248	0.248	0.248
xxiv	Hot-leg		0.125	0.125	0.125	0.125	0.088	0.076	0.072	0.068	0.066
xxiv	Cold-leg - suction		0.750	0.750	0.750	0.716	0.661	0.634	0.626	0.625	0.625
xxiv	Cold-leg - suction		0.750	0.750	0.750	0.680	0.628	0.604	0.598	0.598	0.598
xxiv	Cold-leg - suction		0.750	0.750	0.719	0.630	0.584	0.563	0.559	0.559	0.559
xxiv	Cold-leg - discharge		0.750	0.672	0.544	0.480	0.448	0.437	0.437	0.437	0.437
xxiv	Cold-leg - discharge		0.750	0.583	0.473	0.418	0.393	0.385	0.385	0.385	0.385
xxiv	Cold-leg - discharge		0.750	0.750	0.616	0.542	0.504	0.490	0.488	0.488	0.488
xxv	Hot leg		0.447	0.317	0.259	0.232	0.222	0.222	0.222	0.222	0.222
xxv	Cold leg - suction		0.750	0.750	0.715	0.626	0.580	0.560	0.556	0.556	0.556
xxv	Cold leg - discharge		0.750	0.750	0.750	0.687	0.636	0.613	0.607	0.607	0.607
xxvi	Hot leg		0.418	0.296	0.243	0.218	0.209	0.208	0.208	0.208	0.208
xxvi	Cold leg - suction		0.750	0.720	0.582	0.513	0.478	0.465	0.464	0.464	0.464
xxvi	Cold leg - discharge		0.750	0.750	0.639	0.561	0.522	0.506	0.504	0.504	0.504

Table A-3e PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using BE procedure

Plant identification code	Pipe leg	Crack depth a/t by best estimate procedure as a function of crack length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
i	Hot Leg	1.000	0.614	0.434	0.354	0.315	0.298	0.295	0.295	0.295	0.295
ii	Cross-over		0.855	0.603	0.489	0.433	0.406	0.398	0.398	0.398	0.398
iii	Hot leg		0.791	0.558	0.453	0.401	0.377	0.371	0.371	0.371	0.371
iii	Cold leg		0.679	0.480	0.390	0.346	0.327	0.323	0.323	0.323	0.323
iii	Crossover leg			0.726	0.587	0.517	0.482	0.469	0.468	0.468	0.468
iv	Hot leg		0.791	0.558	0.453	0.401	0.377	0.371	0.371	0.371	0.371
iv	Cold leg		0.679	0.480	0.390	0.346	0.327	0.323	0.323	0.323	0.323
iv	Crossover leg			0.726	0.587	0.517	0.482	0.469	0.468	0.468	0.468
v	Hot leg		0.754	0.533	0.433	0.384	0.361	0.356	0.356	0.356	0.356
v	Cold leg		0.617	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
v	Crossover leg		0.916	0.646	0.523	0.462	0.433	0.423	0.423	0.423	0.423
vi	Hot leg		0.754	0.533	0.433	0.384	0.361	0.356	0.356	0.356	0.356
vi	Cold leg		0.617	0.436	0.355	0.316	0.299	0.296	0.296	0.296	0.296
vi	Crossover leg		0.916	0.646	0.523	0.462	0.433	0.423	0.423	0.423	0.423
vii	Hot leg		0.829	0.585	0.475	0.419	0.394	0.386	0.386	0.386	0.386
viii	Hot leg		0.643	0.454	0.370	0.328	0.310	0.307	0.307	0.307	0.307
ix	Hot leg		0.643	0.454	0.370	0.328	0.310	0.307	0.307	0.307	0.307
x	Hot leg		0.778	0.549	0.445	0.394	0.370	0.364	0.364	0.364	0.364
xi	Hot leg		0.778	0.549	0.445	0.394	0.370	0.364	0.364	0.364	0.364
xii	Hot leg		0.738	0.522	0.425	0.377	0.356	0.351	0.351	0.351	0.351
xii	Crossover leg		0.652	0.461	0.376	0.335	0.317	0.314	0.314	0.314	0.314
xii	Cold leg		0.751	0.531	0.432	0.383	0.362	0.357	0.357	0.357	0.357
xiii	Hot leg		0.731	0.516	0.419	0.372	0.350	0.345	0.345	0.345	0.345
xiv	Hot leg		0.731	0.516	0.419	0.372	0.350	0.345	0.345	0.345	0.345
xv	Hot leg		0.766	0.541	0.440	0.391	0.368	0.363	0.363	0.363	0.363
xvi	Hot leg		0.791	0.558	0.453	0.401	0.377	0.370	0.370	0.370	0.370
xvii	Hot leg		0.961	0.678	0.549	0.485	0.454	0.444	0.443	0.443	0.443
xvii	Cold leg		0.604	0.428	0.349	0.311	0.295	0.293	0.293	0.293	0.293
xvii	Crossover leg		0.836	0.590	0.479	0.425	0.399	0.393	0.393	0.393	0.393
xviii	Hot leg		0.961	0.678	0.549	0.485	0.454	0.444	0.443	0.443	0.443
xviii	Cold leg		0.604	0.428	0.349	0.311	0.295	0.293	0.293	0.293	0.293
xviii	Crossover leg			0.590	0.479	0.425	0.399	0.393	0.393	0.393	0.393

Table A-3e PWR coolant piping information and calculated values by plant – Calculated surface-flaw geometries using BE procedure, continued

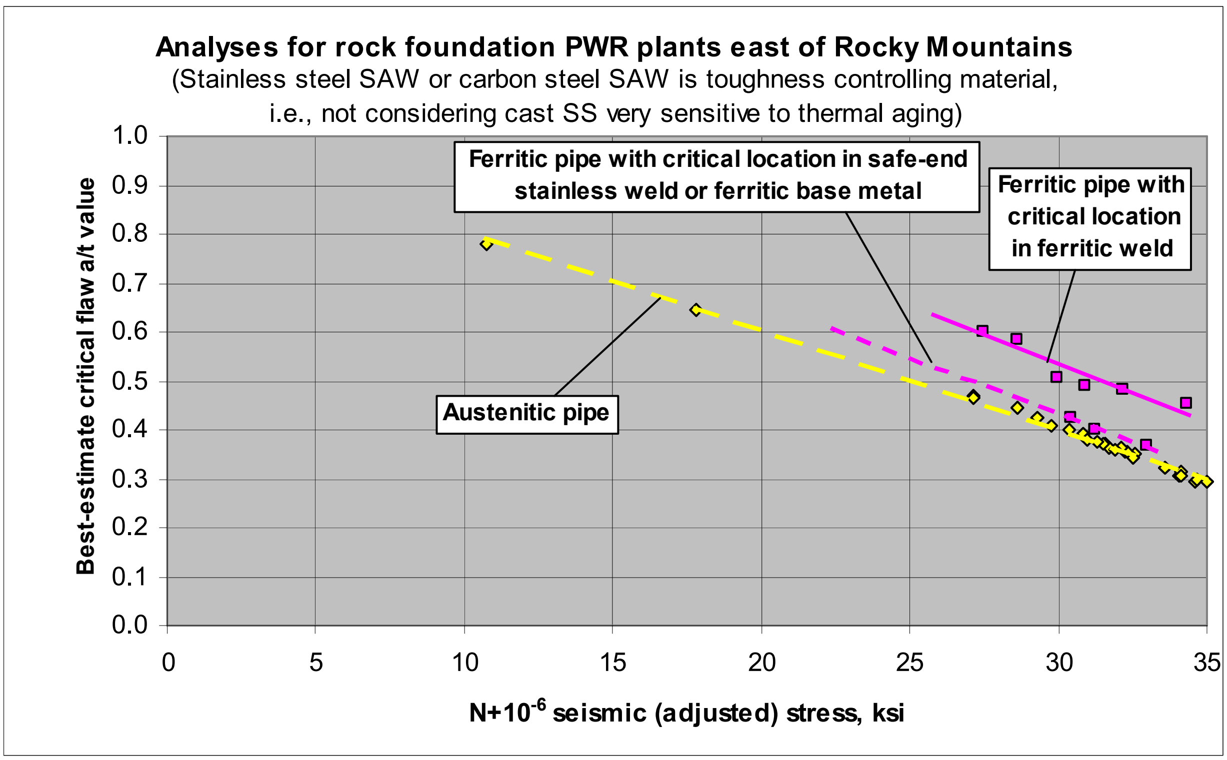
Plant identification code	Pipe leg	Crack depth a/t by best estimate procedure as a function of crack length									
Crack length / pipe circumference		0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1
xix	Hot leg		0.887	0.625	0.507	0.447	0.419	0.410	0.410	0.410	0.410
xx	Hot leg			0.725	0.586	0.516	0.481	0.468	0.467	0.467	0.467
xx	Cold leg				0.851	0.742	0.684	0.656	0.646	0.645	0.645
xx	Crossover leg					0.912	0.836	0.798	0.781	0.777	0.776
xxi	Hot leg			0.725	0.586	0.516	0.481	0.468	0.467	0.467	0.467
xxi	Cold leg				0.851	0.742	0.684	0.656	0.646	0.645	0.645
xxi	Crossover leg					0.912	0.836	0.798	0.781	0.777	0.776
xxii	Hot leg		0.802	0.566	0.459	0.406	0.382	0.375	0.375	0.375	0.375
xxii	Cold leg		0.646	0.456	0.371	0.330	0.311	0.308	0.308	0.308	0.308
xxii	Crossover leg		0.819	0.578	0.469	0.414	0.389	0.381	0.381	0.381	0.381
xxiii	Hot leg		0.768	0.542	0.440	0.390	0.367	0.361	0.361	0.361	0.361
xxiv	Hot-leg		0.919	0.648	0.525	0.464	0.435	0.425	0.425	0.425	0.425
xxiv	Hot-leg			0.778	0.629	0.553	0.515	0.500	0.499	0.499	0.499
xxiv	Cold-leg - suction		0.886	0.624	0.506	0.447	0.419	0.410	0.410	0.410	0.410
xxiv	Cold-leg - suction			0.760	0.614	0.540	0.503	0.488	0.486	0.486	0.486
xxiv	Cold-leg - suction			0.605	0.491	0.434	0.407	0.398	0.398	0.398	0.398
xxiv	Cold-leg - discharge		0.811	0.572	0.465	0.411	0.386	0.379	0.379	0.379	0.379
xxiv	Cold-leg - discharge			0.716	0.579	0.510	0.476	0.463	0.462	0.462	0.462
xxiv	Cold-leg - discharge		0.782	0.552	0.448	0.397	0.373	0.367	0.367	0.367	0.367
xxv	Hot leg			0.965	0.777	0.679	0.629	0.605	0.599	0.599	0.599
xxv	Cold leg - suction			0.767	0.620	0.544	0.507	0.492	0.490	0.490	0.490
xxv	Cold leg - discharge			0.696	0.564	0.498	0.466	0.455	0.455	0.455	0.455
xxvi	Hot leg			0.934	0.753	0.659	0.610	0.588	0.583	0.583	0.583
xxvi	Cold leg - suction			0.799	0.645	0.566	0.527	0.510	0.508	0.508	0.508
xxvi	Cold leg - discharge			0.748	0.605	0.532	0.495	0.481	0.480	0.480	0.480

Appendix B

Additional Calculations for Cases in NUREG-1903 Considering Thermal Aging Effects on Stainless Steel Welds

This appendix performs additional sample calculations for the case in NUREG-1903 considering the effects of long-term thermal aging degradation on the toughness of stainless steel welds. This appendix will include the following;

- Figure showing thermal aging effects on J-R curve of stainless steel weld metal,
- Discussion on effect of weld metal strength change with aging,
- Calculated Z-factors for aged and unaged cases,
- Similar tables to Tables A-3c, A3d, and A3e in Appendix A for surface flaw depth values as a function of length
- Summary plots showing how aging affects critical flaw size values – similar to figure below (Blue dashed line is a schematic of the affect of aging SS welds on critical flaw size. Actual curve will be provided in Appendix).,



Appendix C

Sample Calculations

This appendix provides sample calculations for guidance.

Case 1—Example Calculation for Junction between Cold Leg and Reactor Coolant Pump (Materials are Unaged Cast Austenitic Stainless Steel Joined by a Shielded Metal Arc Weld/Submerged Arc Weld)

This is a case that is similar to one in NUREG-1903 (Appendix A tables), but uses the precise temperatures rather than rounding them off to 550 degrees Fahrenheit (F) or 600 degrees F.

Steps in the Analysis

1. Obtain seismic hazard curve coefficients

   a. Seismic hazard curve is defined by the Weibull equation fit for peak ground acceleration (PGA) versus probability of occurrence (values correspond to plant “U” in Table A-2)
   b. The equation is given by:

$$P(x) = Scale \cdot \alpha \cdot \beta^{-\alpha} x^{\alpha-1} e^{-(x/\beta)^{\alpha}} \tag{C.1}$$

   Where,
   Scale = 0.181
   α = 0.462
   β = 15.20
   χ = PGA in units of centimeter per square second (cm/s^2) in Equation C.1.

2. Obtain SSE design PGA value (values correspond to plant “U” in Table A-2)

   a. Original design PGA value = 0.200 g or = 0.2g * 980.6688 cm/s^2/g = 196.134 cm/s^2
   b. Solving for P(χ) for 196.134 cm/s^2 gives P(χ) = 5.34x10^{-5}

3. Solve for PGA value at 1x10^{-6} probability of occurrence, and obtain ratio of PGA at 1x10^{-6} to PGA at safe-shutdown earthquake (SSE).

   a. Solving for χ for P(x) = 1x10^{-6} gives χ = 859.0 cm/s^2 or χ = 0.876 g
   b. Ratio of PGA for 1x10^{-6} to SSE value is 0.876/0.200 = 4.380

4. Determine the highest SSE stress location (values correspond to plant “v” in Tables 3a, b, and c).

   a. This information can be obtained from past LBB submittals or other plant design information.
   b. In this example, the worst-case location is the junction of the cold leg and the reactor coolant pump outlet nozzle (i.e., the highest stressed location was location 11 at the reactor coolant pump outlet nozzle to pipe weld).

5. Determine the materials of interest at the critical location.

a. There is a shielded metal arc weld/submerged arc weld (SMAW/SAW) weld between the pump nozzle and stainless steel elbow.
b. The base metal on either side of the weld is CF8A cast austenitic stainless steel.

6. Determine the pipe cross-sectional dimensions at critical location (i.e., outside diameter and thickness).

a. For plant "v" in Table A-3a, the inside diameter of the pipe is 27.5 inches and the pipe thickness is 2.32 inches.
b. The outside diameter is calculated to be 32.14 inches.

7. Determine normal operating conditions/stresses (values correspond to plant "v" in Table 3b).

a. Normal operating pressures and temperatures are 2,305 pounds per square inch gauge and 557 degrees F, respectively.
b. The maximum normal operating stress including the pressure stress, deadweight, and thermal expansion stress is 10.08 kilopounds per square inch (ksi).

8. Determine strength values for materials of interest.

a. Using Code Material Properties

i. For TP304N at 557 degrees F, the S_y value is 20.37 ksi (interpolated from Table Y-1 in Section III, Part D, 2007 American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (BPV) Code).
ii. For TP304N at 557 degrees F, the S_u value is 70.35 ksi (interpolated from Table U in Section III, Part D, 2007 ASME BPV Code).
iii. The flow stress (average of yield and ultimate strengths) is equal to 45.36 ksi.
iv. S_m at 557 degrees F is 18.33 ksi (interpolated from Table 1a of Section III Part D 2007.

b. Using Actual Material Properties (Values Obtained from PIFRAC Database [Ref. 39][1])

i. For TP304N at 550 degrees F, the Sy value is 22.45 ksi.
ii. For TP304N at 550 degrees F, the Su value is 64.16 ksi.
iii. The flow stress (average of yield and ultimate strengths) is equal to 43.31 ksi.

9. Determine the SSE stresses (value corresponds to plant "v" in Table 3b).

a. The SSE design stress in the cold-leg pipe at this location is 21.45 ksi.

10. Determine the linearly scaled seismic stress for the 1×10^{-6} seismic event.

a. The value is the SSE stress multiplied by the ratio of PGA at 1×10^{-6} to PGA at SSE from Step 3.
b. This stress is 4.38* 21.45 ksi = 93.93 ksi.

---

[1] Average values of yield and ultimate strength at 550F also in Table 3.1 of NUREG/CR-6004

11. Apply seismic scaling factor for plant site to correct the linearly scaled stresses from Step 10 and add the normal operating stresses.

    a. The seismic scaling factors for the different plant sites account for conservatisms in the original seismic design analysis to obtain a BE value. It is equivalent to the reciprocal of the safety factor in the original design.
    b. The seismic scaling factor is 0.528 (value corresponds to plant "v" in Table A-3b).
    c. The correction to the linearly scaled stresses (from Step 10) is 0.528 * 93.93 ksi = 49.59 ksi.
    d. The normal plus 1×10^{-6} seismic stress (S_{EI}) is 49.59 + 10.08 ksi = 59.68 ksi.

12. Apply nonlinear correction factor to the elastic N + 1×10^{-6} seismic stresses from Step 11 to obtain the nonlinear stress (S_{NL}).

    a. The nonlinear correction is an approximate correction to account for material plasticity in the subsequent elastic-plastic fracture mechanics (EPFM) analysis.
    b. The correction factor was developed in NUREG-1903 by assuming that the stress strain curve is bilinear as illustrated in Figure C-1 below.
    c. If S_{EI} (from Step 11) is below the yield strength then the correction factor = 1.0 and

$$S_{NL} = S_{EI} \tag{C.2a}$$

    d. If $S_{EI} > S_y$ then, from Figure C-1 for TP304N, S_{NL} is

$$S_{NL} = 0.2357^*S_{EI} + 15.569 \tag{C.2b}$$

    e. In this example S_{EI} = 59.68 ksi, S_{NL} (from Equation C.2b) = 0.2357* 59.68 + 15.502 = 29.566 ksi.

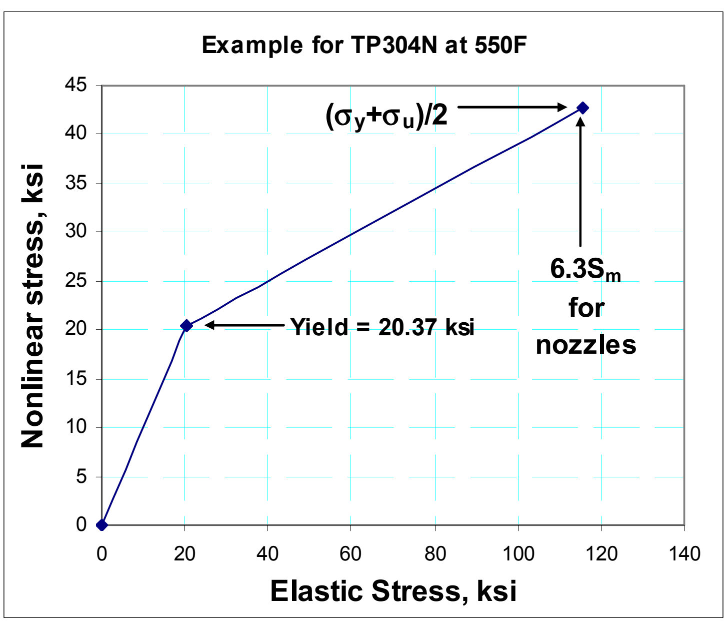


Figure C-1 Elastic-stress correction curves for TP304N using typical actual strength values at 550F and S_m at 557 degrees F

13. Determine the elastic-plastic correction factor (Z-factor) for the critical flaw size evaluation.

   a. To simplify the EPFM analysis, the ASME Code, Section XI, developed the Z-factor.
   b. The Z-factor is the ratio of the failure stress from the limit-load equation to the failure stress from an EPFM analysis. The Z-factor is a function of the material, pipe diameter, and crack length.
   c. At each pipe diameter, Z-factors are calculated for a variety of crack lengths and the maximum Z-factor is conservatively used.
   d. The Z-factors in the ASME Code, Section XI—

      i. Are derived from General Electric/Electric Power Research Institute J-estimation schemes for a circumferential through-wall crack in a pipe in bending
      ii. Assume that the material fracture resistance is represented by a deformation plasticity J-R curve.

   e. In NUREG-1903, the Z-factors have been derived using relationships that more accurately (and less conservatively) predict full-scale pipe test failure. These Z-factors were derived using the following:

      i. More accurate J-estimation scheme
      ii. A crack-growth corrected modified J-R curve
      iii. J-R curve properties at seismic loading rates
      iv. A method to account from the cyclic loading that occurs during a seismic event

   f. In this example—

      i. The SAW/SMAW J-R curve is the mean minus 1 standard deviation curve with a multiplier of 1.08 to account for cyclic and dynamic loading effects on the J-R curve as given in NUREG-1903. A simple linear J-R_M curve was with $J = 1{,}047 + 4{,}333\Delta a$ (in-lb/in^2 with Δa in inches).
      ii. The Z-factor was derived for PWR primary piping with R/t of 5 to 5.5.
      iii. The outside diameter (OD) of the cold-leg pipe (value corresponds to plant "v" in Table 3a) is 32.14 inch.
      iv. The Z-factor for this case is given by Equation C.3 below and is 1.637.

$$Z = -0.00000000501D^6 + 0.00000071875D^5 - 0.00004102D^4 + 0.0011889D^3 - 0.0185D^2 + 0.15025D + 1.0922 \qquad \text{(C.3)}$$

Where,
D = pipe outside diameter, inch

14. Determine EPFM-corrected stress (S_{EC}) for use in limit-load equations.

   a. The EPFM-corrected stress is the Z-factor (from Step 13) multiplied by nonlinear stress (from Step 12).
   b. In this example, the S_{EC} = 1.637 * 29.566 ksi = 48.344 ksi.

15. Determine the minimum critical surface flaw depth from limit-load equations.

a. The limit-load equations are provided in ASME Code, Section XI, Appendix C. They are also replicated in Equations C4a–C4c below for convenience. Note that in this calculation, the structural factor (SF) values in ASME Code, Section XI, Appendix C, are set equal to 1.0.

b. For a long surface crack, the limit-load equations (from Article C-5321 of ASME Code, Appendix C, of Section XI) are:

$$\sigma_b^c = (2\sigma_f/\pi)(2\text{-}a/t)\sin(\beta) \qquad \text{(C.4a)}$$

$$\beta = \pi/(2\text{-}a/t)(1\text{-}a/t\text{-}\sigma_m/\sigma_f) \qquad \text{(C.4b)}$$

Where,
σ_b^c = critical bending stress at net-section-collapse (limit-load)
σ_f = flow stress (average of yield and ultimate strength)
a = depth of surface flaw (assumed constant depth)
t = pipe thickness
β = fully plastic neutral axis as measured from the bottom of the pipe, radians
σ_m = axial membrane stresses (frequently taken as the pressure-induced axial stress)

c. Equations C4a and C4b can be rearranged to give:

$$a/t = 2 - [(\pi/2)(\sigma_b^c/\sigma_f)]/\sin[\pi/(2\text{-}a/t)(1\text{-}a/t\text{-}\sigma_m/\sigma_f)] \qquad \text{(C.4c)}$$

i. This equation is solved iteratively for the a/t value.

d. In this example—

σ_m = 7.980 ksi (from pressure stress, using PD/4t with D = OD per ASME Code equations)
σ_f = 45.36 ksi (using ASME Code properties from Step 8.a.3) or 43.31 ksi (using actual properties from Step 8.b.4)
σ_m/σ_f = 0.176 (using ASME Code properties) or 0.184 (using actual properties)
σ_b^c = 48.344 ksi (S_{EC} from Step 14) minus 7.980 ksi (σ_m from above) = 40.36 ksi
σ_b^c/σ_f = 0.890 (using ASME Code properties) or 0.932 (using actual properties)

e. Solving Equation C.4c iteratively with the above σ_b^c/σ_f and σ_m/σ_f values gives a/t values of 0.301 using ASME Code properties and 0.262[2] using actual properties.

16. Calculate the a/t value corresponding to ASME Service Level D loading.

a. Determine the original plant N+SSE stresses for cold-leg location (values correspond to plant "v" in Table 3b).

---

[2] The 0.262 BE value is lower than the 0.296 value given in Table A-3e because the NUREG-1903 analysis assumed all the piping was CF8A. The typical actual strengths of the TP304 were at the ASME Code values.

i. SSE stress = 21.45 ksi
ii. N stress = 10.08 ksi for the normal operating stress
iii. The total N+SSE = 31.53 ksi

b. Determine membrane (σ_m), bending (σ_b), and thermal expansion plus seismic anchor motion (σ_e) stress components. In this example—

i. σ_m = 7.98 ksi
ii. σ_b = 22.86 ksi
iii. σ_e = 0.69 ksi

c. Determine the bending collapse stress (σ_b^c).

i. From Article C-6321 in Appendix C to ASME Code, Section XI, 2007 edition:

$$S_c = (1/SF_b)[\sigma_b^c/Z - \sigma_e] - \sigma_m[1 - 1/(Z\ SF_m)] \quad \text{(C.5a)}$$

Where,
S_c = maximum allowable bending stress for circumferentially flawed pipe
SF_b = structural factor for bending loads for service level D loading
SF_m = structural factor for membrane loads for service level D loading
Z = ASME Z-factor for austenitic SMAW/SAW weldments
NPS = Nominal pipe size in inches. For primary piping use the outside diameter for the nominal pipe size.

ii. Solving Equation C.5a for σ_b^c yields the following:

$$\sigma_b^c = Z\ SF_b\ \{S_c + \sigma_m[1 - 1/(Z\ SF_m)] + \sigma_e)\} \quad \text{(C.5b)}$$

iii. In this example—

S_c = σ_b = 22.86 ksi (from Step 16.b.2)
SF_b = 1.4 (from Article C-2621 of ASME Code, Section XI, Appendix C)
SF_m = 1.3 (from Article C-2621 of ASME Code, Section XI, Appendix C)
σ_e = 0.69 ksi (from Step 16.b.3)
σ_m = 7.98 ksi (from Step 16.b.1)
NPS = 32.14 inch (value corresponds to plant "v" in Table A-3a)
Z = 1.30(1 + 0.010(NPS -4) = 1.664 (from Article C-6330 of ASME Code, Section XI, Appendix C – using the pipe actual OD of 32 inches), and
σ_b^c = 64.858 ksi (from Equation C.5b)

d. Iteratively solve for the a/t value using Equation C.4c from Step 15.c.

i. In this example, using both the Code and typical average strength values, a/t is less than 10% of the pipe thickness, so the flaw acceptance standards in Table IWB-3514-2 have to be used.

17. Compare BE a/t value from Step 15.e to the ASME Code a/t value from Step 16.d.

a. If the ASME Code a/t value is less than the BE a/t value, then the pipe system passes the seismic consideration assessment for the TBS.
b. If the ASME Code a/t value is greater than the BE a/t value, then the BE a/t value should be used for comparison with minimum flaw acceptance criteria
c. In this example, the ASME Code a/t value for the IWB-3514-2 tables is less than the BE $1x10^{-6}$ seismic a/t value using the ASME Code strengths (0.301), and the ASME Code value (0.301) is greater than 0.3 (the minimum acceptable flaw size).
d. Consequently, this example passes the TBS requirements.