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DRAFT REGULATORY GUIDE

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(Proposed New Regulatory Guide)

PLANT-SPECIFIC APPLICABILITY OF TRANSITION BREAK SIZE SPECIFIED IN 10 CFR 50.46a

A. INTRODUCTION

This is a proposed new regulatory guide written to support implementation of proposed rulemaking setting forth an alternate approach for evaluating the performance of an emergency core cooling system (ECCS). The proposed rule, 10 CFR 50.46a, "Risk-Informed Changes to Loss-of-Coolant Accident Technical Requirements," was published as in the Federal Register on August 10, 2009, (Ref. 1). The NRC regulatory framework for nuclear power plants consists of a number of regulations and supporting guidelines, including, but not limited to, General Design Criterion (GDC) 35, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors," as set forth in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities" (Ref. 2) and 10 CFR 50.46a. GDC 35 states, in part, that the licensee must calculate emergency core cooling system (ECCS) cooling performance in accordance with an acceptable evaluation model. Furthermore, the licensee must calculate ECCS cooling performance for a number of postulated loss-of-coolant accidents (LOCAs) of different sizes, locations, and other properties sufficient to provide assurance that the evaluation considered the most severe postulated LOCAs. The proposed 10 CFR 50.46a would provide an alternative to the existing, conservatively-set deterministic requirements for evaluating the performance of ECCS systems.

Section 50.46a would contain alternative requirements for ECCS at nuclear power reactors established by using risk information based on the likelihood of pipe breaks of different sizes. The rule would divide all coolant piping breaks currently considered in emergency core cooling requirements into two size groups: breaks up to and including a "transition break size", and breaks larger than the transition size up to the largest pipe in the reactor coolant system. Selection of the transition size was based upon pipe break frequency estimates, the associated uncertainties, and the need to provide regulatory stability to guard against changes resulting from any future increases in the LOCA frequency estimates. Because pipe breaks smaller than the transition break size are considered more likely they would be analyzed using existing criteria for ensuring the reactor core stays cool during and after an accident. Larger breaks are considered less likely and would be analyzed with less conservative methods, but plants would still have

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to mitigate the effects of failure of the largest pipe and maintain core cooling. After the final rule is issued, power plant operators could make plant design changes that could enhance safety and/or provide operational benefits. The rule also specifies risk acceptance criteria to ensure that modified designs would continue to provide adequate protection of public health and safety.

This draft guide describes a method that the staff of the U.S. Nuclear Regulatory Commission (NRC) considers acceptable for demonstrating that the generic transition break size (TBS) specified in the proposed 10 CFR 50.46a is applicable to a specific plant. The proposed rule would require a licensee to conduct the evaluation described herein either before, or as part of, the initial application to modify a nuclear power plant under the proposed rule. The proposed rule would also require a more limited evaluation to demonstrate the continued applicability of the TBS after each subsequent plant modification. The entire evaluation is greatly simplified for plants that the NRC has approved for license renewal. The evaluation is also simplified for plants that the NRC has approved for leak before break (LBB) or that have applied for license renewal.

This guide only applies to light-water reactor designs that have received a construction permit or operating license prior to January 1, 2000. This guide does not apply to new light-water (i.e., evolutionary and passive) or to non-light water (i.e., high temperature gas or liquid metal) reactor designs. Supplemental guidance for applying 10 CFR 50.46a to these reactor designs will be developed at a later date as needed.

The NRC issues regulatory guides to describe to the public methods that the staff considers acceptable for use in implementing specific parts of the agency's regulations, to explain techniques that the staff uses in evaluating specific problems or postulated accidents, and to provide guidance to applicants. Regulatory guides are not substitutes for regulations and compliance with them is not required.

This regulatory guide contains information collection requirements covered by 10 CFR Part 50 that the Office of Management and Budget (OMB) approved under OMB control number 3150-0011. The NRC may neither conduct nor sponsor, and a person is not required to respond to, an information collection request or requirement unless the requesting document displays a currently valid OMB control number.

B. DISCUSSION

Background

The 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) TBSs under 10 CFR 50.46a. NUREG-1829, "Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process," issued April 2008 (Ref. 3), 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. 4), assessed the likelihood that rare seismic events would induce primary system failures larger than the postulated TBS. This latter 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 do not apply to any specific nuclear plant. The study documented in NUREG-1829 was intended 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-year fleet average), end-of-plant license (40-year fleet average), and end-of-plant license renewal (60-year fleet average). These estimates are based on the responses from an expert panel and 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 considered broad differences among plants related to important variables (i.e., plant system, material, geometry, degradation mechanism, loading, mitigation and 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 in general, sufficient commonality among plants exists to enable a meaningful generic assessment.

The NUREG-1829 study also relied on several implicit and explicit assumptions regarding plant design and operation and regulatory oversight. For example, the study assumed 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 have 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. The NRC staff chose this focus 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 separate research 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. This study was not intended to perform bounding seismic analyses that encompass all potential plant-specific variations, including site-to-site variability in the seismic hazard. Rather, the study evaluated 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 (yr) or less because this LOCA frequency was used as the basis for establishing the TBS.

The study did demonstrate generically 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}/yr, 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}/yr and 10^{-6}/yr. 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}/yr. The analysis of indirect failure frequencies updated prior plant-specific studies conducted by Lawrence Livermore National Laboratory (LLNL) using more recent seismic hazard and group motion information (Ref. 4). 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}/yr.

Because of the objectives and approaches followed in these studies, unique plant attributes may result in plant-specific LOCA frequencies caused by normal operational or seismic loading or both that are greater than the frequencies reported in either NUREG-1829 or NUREG-1903. As a result, the Commission directed the NRC staff in the staff requirements memorandum associated with 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. 5), to require applicants[2] "to justify that the generic results in the revised NUREG-1829…are applicable to their individual plants." Additionally, the Commission directed the staff to "develop regulatory guidance that will 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. 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. 4).

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[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 or 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.

General Considerations

The recommendations of this guide can be used to demonstrate that the generic TBS (i.e., for BWR or PWR plants, as applicable) based on the NUREG-1829 and NUREG-1903 studies is applicable to a specific plant. As discussed in 10 CFR 50.46a, the TBS is used to delineate primary system pressure boundary breaks of different sizes. The existing requirements in 10 CFR 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors,” 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 the 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 used in the development of the NUREG-1829 and NUREG-1903 results. This guide 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. The NRC considers these methods and acceptance criteria to be acceptable for demonstrating the plant-specific applicability of both NUREG-1829 and NUREG-1903. However, the NRC may also find alternative approaches and criteria to be acceptable.

B.1 NUREG-1829 Applicability

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, service environment, loading history, age-related degradation mechanism, geometry and configuration, and maintenance and mitigation 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. In addition, the elicitation assumed 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, this regulatory guide does not contain any additional guidance on any other plant components or systems.

These additional evaluations only pertain to age-related degradation mechanisms in the PLP and PBSC 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 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.

The applicant is not required to validate the assumption 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 (referred to hereafter as the ASME Code) (Ref. 6), Section III or ASME B31.1 (Ref. 7) 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. 8) The NRC reviews this information before granting either a construction, operating, or combined license. Similarly, either Section III or Section XI of the ASME Code provides requirements governing repair and replacement activities associated with the PLP and PBSCs. The NRC staff has reviewed the acceptability of the existing requirements of ASME Code, Sections III and XI, and continually reviews new requirements to ensure that these standards comply with the required regulations. The regulations at 10 CFR 50.55a, "Codes and Standards," govern the acceptability of these standards, along with any required exceptions or conditions.

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.

B.1.1 Aging Management

As previously discussed, the TBS was based, in part, on the estimates contained in NUREG-1829 of the current-day and future failure frequencies for long-lived, primary pressure boundary, passive systems, structures, and components (SSCs). The elicitation that formed the basis for these generic estimates utilized certain assumptions related to the aging management of these SSCs. One fundamental assumption was that plants will continue to comply with their licensing basis throughout the period of plant operation. Additionally, the elicitation assumed that plants are implementing aging management best practices for the applicable SSCs. These best practices include required SSC inspections and adoption of aging management programs for relevant SSCs. These assumptions were necessary in the elicitation to preclude consideration of the effects of significant plant-specific differences in the maintenance of these SSCs so that generic results could be developed.

The elicitation further assumed that current regulatory oversight practices will continue to evaluate aging management and mitigation strategies in order to reasonably assure that future plant operation and maintenance has equivalent or decreased risk. The NRC's process for issuing renewed operating licenses under 10 CFR Part 54 constitutes a regulatory oversight process for evaluating a licensee's aging management and mitigation activities. Thus, a licensee who has been issued a renewed operating license only needs to verify that current aging management practices are consistent with the licensing basis (LB) applicable within the renewal period for relevant SSCs in its § 50.46a application. However, licensees that have not been issued a renewed operating license should first demonstrate that they are complying

[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.

with their licensing basis with respect to ensuring functionality and operability of relevant SSCs consistent with their design bases, as part of complying with the section 50.46a requirement that the applicant demonstrate the applicability of the results in NUREG-1829.

Acceptable methods for demonstrating the sufficiency of an applicant's management of aging in relevant SSCs is set forth in Section C.1 while additional detail is provided in Section B.1. However, generally, the evaluation of a plant's adherence to the LB and demonstration of the sufficiency of PLP and PBSC aging management is consistent with the NRC's license renewal (LR) regulatory philosophy. Applicants may utilize relevant information from plant evaluations provided to address LR requirements as part of the basis for demonstrating the applicability of NUREG-1829.[4] However, plants shall implement aging management programs that are planned for the LR period during the current operating period in order to demonstrate applicability of the NUREG-1829 results. Alternatively, applicants may use a separate or supplemental evaluation. Figure 1 (found at the end of this section) illustrates the process for this phase of the evaluation.

B.1.1.1 Primary Water Stress-Corrosion Cracking

The NRC is currently addressing the emergence of PWSCC in dissimilar metal welds (DMWs) in PWR environments outside of the context of LR; therefore, it is an initial evaluation requirement within the process. Only PWR plants should address this topic. Currently, PWR plants follow MRP-139, "Material Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline" (Ref. 9), for guidance on the volumetric and visual inspections of butt welds in primary systems. However, the staff considers the inspection requirements for DMWs that are currently being developed within the ASME Code to be a more permanent solution.

B.1.1.1.1 *<u>Primary Water Stress-Corrosion Cracking Location and Mitigation</u>*

The DMWs in the PLP and PBSC are susceptible to PWSCC. Those DMWs manufactured from Alloy 600 and its associated weld metals (i.e., Alloys 82 and 182) are more susceptible than Alloy 690 materials (i.e., Alloys 690, 52, and 152). In many locations, PWSCC mitigation consists of applying Alloy 690 materials to the original Alloy 600 DMW. Full-structural and optimized weld overlays apply Alloy 690 materials around the outside diameter of the piping, while inlays and onlays apply this material around the inside diameter of the piping. The mechanical stress improvement (MSI) process provides mitigation by squeezing the DMW to induce compressive stress over approximately the inner 50 percent of the piping thickness (Ref. 10). This mitigation process does not add additional Alloy 690 materials. In this part of the evaluation, the applicant should consider all the DMWs in the PLP and PBSC and document and describe the PWSCC mitigation method applied to each DMW. The significance of deviations from applicable codes and standards is an important consideration in demonstrating the acceptability of the mitigation method.

B.1.1.1.2 *<u>Primary Water Stress-Corrosion Cracking Inservice Inspection Program</u>*

Most PWSCC mitigation techniques require that the DMWs undergo periodic inservice inspection (ISI) to ensure that crack growth does not continue after enacting mitigation. As indicated previously, plants currently adhere to the inspection guidance in MRP-139. However, ASME has developed draft Code Case N-770, "Alternative Examination Requirements and Acceptance Standards for

[4] Note that the LR regulatory framework is only used to demonstrate that a plant is consistent with 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.

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. 11), to provide Code-approved inspection requirements. This Code case, and any associated NRC conditions, provides the basis for the applicant's program to inspect for PWSCC.

B.1.1.2 Aging Management Programs and Time-Limited Analysis

NUREG-1801, "Generic Aging Lessons Learned (GALL) Report Summary," issued September 2005 (referred to hereafter as the GALL Report) (Ref. 12), addresses the applicable inspection and mitigation activities associated with age-related degradation and describes appropriate time-limited aging analysis (TLAA) for susceptible components. 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, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued September 2005 (hereafter referred to as the SRP-LR) (Ref. 13), 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.

The GALL Report addresses aging in all major plant sections, with the exception of the refueling water, chilled water, residual heat removal, condenser circulating water, and condensate storage systems in PWR and BWR plants. The report subsequently addresses aging within each plant section for each principal component 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 the applicant should address 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. The GALL Report and the SRP-LR provide more details on the relevant AMP and TLAA evaluations discussed within this regulatory guide.

B.1.1.2.1 *<u>Evaluation Option I: License Renewal Approval</u>*

This option (see Figure 1) is intended for applicants that have been approved for LR and allows these applicants to credit LR approval as a basis for demonstrating adherence to the LB.

B.1.1.2.2 *<u>Evaluation Option II: License Renewal Submittal</u>*

This option (see Figure 1) is intended for applicants that have submitted LR applications but have not been approved by the NRC for LR. This option allows the applicant to reference and credit the AMPs associated with the LR period that have been submitted for approval. The applicant should also discuss the significance of any deviations with the GALL Report and SRP-LR guidance and demonstrate that the AMPs satisfy the applicable regulatory requirements.

B.1.1.2.3 *<u>Evaluation Option III: Alternative Evaluation</u>*

B.1.1.2.3.1 Cast Austenitic Stainless Steel

This option (see Figure 1) is intended for applicants that have not applied for LR and is modeled after the LR process. Consequently, the applicant may structure its evaluation to demonstrate adherence to the LB in a manner similar to an LR application. In this evaluation, the applicant should demonstrate that the applicable regulatory requirements associated with the PLP and PBSC are met. Additionally, the applicant should commit to implementing AMPs that satisfy the GALL Report and SRP-LR requirements before enacting any plant changes under 10 CFR 50.46a. The evaluation should also address the specific topics discussed in the following paragraphs.

Cast austenitic stainless steel (CASS) materials within the PLP and PBSC are potentially susceptible to loss of fracture toughness due to thermal embrittlement at reactor coolant system operational temperatures. A letter from C.I. Grimes (NRC) to D.J. Walters of the Nuclear Energy Institute (NEI), dated May 19, 2000, and entitled “License Renewal Issue No. 98-0030, ‘Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components’” (Ref. 14), provides criteria for determining whether a particular CASS material is susceptible. In this evaluation, applicants should consider the susceptibility of each unique production heat number of CASS material within the PLP and PBSC.

The applicant should also commit to implement an AMP that adequately addresses potentially susceptible material.

B.1.1.2.3.2 Inservice Inspection

Sections B.1.1.1.2 and C.1.1.1.2 of this regulatory guide address ISI programs for PWSCC in PWR plants. Sections B.1.1.2.3.4 and C.1.1.2.3.4 of this guide address ISI programs for IGSCC in BWR plants. This section addresses both general ISI programs and programs that address other specific degradation mechanisms within the PLP and PBSCs. These ISI programs may be in place to satisfy ASME Code requirements; adhere to an NRC-approved, risk-informed ISI program; address requirements associated with specific degradation mechanisms (i.e., thermal fatigue); or adhere to industry guidance (i.e., NEI 03-08, “Guidelines for the Management of Materials Issues” (Ref. 15)).

B.1.1.2.3.3 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). Effective water chemistry protects against stress-corrosion cracking (SCC) in primary pressure boundary components in both BWR and PWR plants. For PWRs, two Electric Power Research Institute (EPRI) reports provide primary and secondary system water chemistry guidelines (Refs. 16 and 17, respectively). These guidelines incorporate the latest field and laboratory data on materials corrosion and performance issues.

The primary system guidelines (Ref. 16) help to ensure the continued integrity of reactor coolant system materials. Volume 1 covers operating chemistry and Volume 2 covers startup and shutdown chemistry. The secondary system guidelines (Ref. 17) are intended to reduce equipment corrosion and enhance steam generator reliability. For BWRs, BWRVIP-130, “BWR Vessel and Internals Project BWR Water Chemistry Guidelines—2004 Revision,” issued October 2004 (Ref. 18), provides primary water chemistry guidelines. BWRVIP-130 focuses on the effect of water chemistry on IGSCC, which can be used to greatly increase the service life of susceptible materials and components in BWR water environments. Many plants have adopted hydrogenated water chemistry and incorporated noble metal chemical additions to successfully mitigate IGSCC.

The elicitation considered the effects of both typical primary system temperatures and plant-to-plant temperature differences on 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 represented 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's evaluation should demonstrate that the plant-specific service environment will be maintained within an acceptable range that adheres to the LB and follows applicable industry guidance.

B.1.1.2.3.4 Intergranular Stress-Corrosion Cracking

Sensitized stainless steel PLP and PBSCs have experienced IGSCC in BWR plants. 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. 19), describes the agency's position on IGSCC. Industry has effectively mitigated and monitored IGSCC through a variety of different techniques, including changing water chemistry, using weld overlays of less susceptible materials, generating compressive residual stresses within the inner portions of the piping wall thickness, and enhanced inspection techniques. Industry inspection procedures typically adhere to the guidance in BWRVIP-75, "BWR Vessels and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," issued October 2005 (Ref. 20). The intent of this evaluation is for BWR applicants to demonstrate that they are effectively employing sound IGSCC mitigation and monitoring practices.

B.1.1.2.3.5 Boric Acid Corrosion Control

Regulatory Issue Summary 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. 21), notes that existing boric acid corrosion control (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 21, 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. 22), and N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Welds" (Ref. 23), provide inspection procedures for identifying pressure boundary leakage from Alloy 600 components and DMWs 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 10 CFR 50.55a(g)(6)(ii)(E). These requirements incorporate the aforementioned ASME 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 21.

B.1.1.2.3.6 Time-Limited Aging Analysis

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 will meet the requirements of 10 CFR 54.21(c)(1) (Ref. 24) over the licensing period. SRP-LR, Section 4.3, "Metal Fatigue," provides an acceptable approach for meeting the 10 CFR 54.21(c)(1) requirements. The analysis described in SRP-LR, Section 4.3, and 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, issued March 2007 (Ref. 25), provides one acceptable approach for demonstrating that the fatigue analysis has considered environmental effects. Alternatively, the applicant may 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.

B.1.1.2.3.7 Leak Detection

Adequate leak-detection capabilities provide essential defense in depth to ensure that the structural integrity of the RCPB is maintained. GDC 30, "Quality of Reactor Coolant Pressure Boundary" (Ref. 2), 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 and have been shown to provide sufficient margin against structural failure (Ref. 26). Regulatory Guide 1.45, Revision 1, "Guidance on Monitoring and Responding to Reactor Coolant System Leakage," issued May 2008 (Ref. 27), addresses the types of leakage, leakage separation, methods for monitoring leakage and identifying its source, monitoring system performance, seismic qualification, and leakage management. The NRC recently updated this guidance to address progress in leak-detection technology and reduced reactor coolant system activity resulting from improved fuel integrity. The revised guidance also incorporates lessons learned from operating experience.

B.1.2 Plant-Specific Attributes

This analysis is intended to identify and evaluate 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, service environment, and maintenance and mitigation strategies associated with the PLP and each PBSC. However, Section C.1.1.2 of this regulatory guide provides an appropriate method for demonstrating that the plant-specific environment (e.g., water chemistry) for the PLP and PBSCs is acceptable. Additionally, Sections C.1.1.1 and C.1.1.2 (e.g., ISI, PWSCC mitigation, IGSCC mitigation, leak detection) and Section C.1.2.2 (e.g., snubber reliability) provide methods for demonstrating that maintenance and mitigation strategies for important PLP and PBSC degradation mechanisms are acceptable. Therefore, no additional evidence is required to demonstrate that the plant-specific service environments and maintenance and mitigation practices are consistent with those considered in NUREG-1829.

In this analysis, 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. The analysis of plant-specific attributes contains elements that are typically addressed in an LBB evaluation. In fact, the screening method provided for demonstrating that the plant-specific LOCA frequencies are consistent with the NUREG-1829 estimates is modeled after review procedures in Section 3.6.3, "Leak-Before-Break Evaluation Procedures," of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition" (referred to hereafter as the SRP) (Ref. 28). These procedures are used to evaluate water hammer, corrosion, creep damage, fatigue, erosion, and environmental conditions in piping systems and to demonstrate, in part, that the system has an extremely low probability (i.e., less than 10^{-6}/yr) of rupture, as defined in GDC 4, "Environmental and Dynamic Effects Design Bases."[5] Aspects of the plant-specific analysis are also consistent with the development of risk-informed ISI plans and evaluations for LR. Because of the similarity with aspects of LBB, risk-informed ISI, and LR evaluations, it may be appropriate for the applicant to use information developed for these, and any other relevant, evaluations to address the effects of plant-specific attributes on LOCA frequencies.

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[5] GDC 4 itself does not define this frequency; however, the Statement of Considerations associated with GDC 4 does.

B.1.2.1 Materials

The elicitation summarized in NUREG-1829 addressed the failure propensity associated with all common piping, structural materials, and welds. The elicitation particularly focused 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 energy (USE) values). 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.

Furthermore, the elicitation considered typical locations of these materials within the primary system 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 (see Section C.1.2.1 of this guide) to provide additional justification unless the PLP or RBSCs contain either unique materials not indicated in the above list or common materials in unique locations within the primary system (e.g., Alloy 600 component safe-ends rather than stainless steel).

B.1.2.2 Loading History

Because the NRC intends the LOCA frequency estimates 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 explicitly addressed only 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 transient stresses that result from, for instance, thermal striping, heatup or cooldown, 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 strongly depend on plant-specific factors.

The plant-specific evaluation should ensure that the loading history associated with the PLP and PBSCs is comparable to industrywide conditions. Primary loads associated with steady-state operation and transients associated with reactor startup and shutdown have generally been comparable among plants over approximately the last 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 water hammer, fatigue, snubber failure, rigid support (i.e., hanger and strut) misadjustments, and any other nonseismic transients. The following sections provide more details concerning these loading sources.

B.1.2.2.1 *Water Hammer*

The pressure transients induced by a severe water hammer event (including steam hammer and water slugging) may be sufficient to fail unflawed PLP and PBSCs that meet ASME Code specifications. Degraded PLP and PBSCs may fail under less severe water hammer events. Obviously, the severity of the event required to cause failure decreases as the magnitude of the degradation increases. The focus of this portion of the evaluation is to demonstrate that water hammer events that will challenge the structural integrity of the PLP or the PBSCs are unlikely. This demonstration could be based on an appropriate combination of operating experience, existing or enhanced operating procedures, and plant changes or other steps taken to mitigate water hammer events over the plant's licensing period.

B.1.2.2.2 Fatigue

Loading sources may contribute to either high-cycle or low-cycle fatigue. High-cycle fatigue is generally characterized by higher frequency loading that induces local elastic stresses. Crack initiation leading to failure classically occurs after approximately 10,000 loading cycles. Conversely, low-cycle fatigue typically occurs at lower frequencies, and the local component stresses are plastic. Crack initiation or failure can occur in fewer than 1,000 loading cycles. Fatigue failures can result from alternating thermal loads (e.g., due to striping, stratification, differential expansion, and the pipe wall temperature differential), flow-induced loads (e.g., hydrodynamic), or mechanical loads (e.g., vibration or pressure). The fatigue life of materials used for PLP and PBSC components is reduced in the primary water environment compared to the fatigue life in room temperature air. Hence, an assessment of these environmental effects is used to demonstrate acceptable performance over the licensing period for plants wishing to apply the provisions of 10 CFR 50.46a.

B.1.2.2.3 Rigid support Misadjustments and Snubber Failures

Rigid support misadjustments can significantly alter the PLP design stresses. Accordingly, it is important to document how the process of installing and adjusting the rigid support ensures that unacceptable loads are not induced within the PLP. Quality assurance provisions used to verify that the process is properly enacted is also an important consideration. The failure of any snubbers that remain within the PLP can also 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.

B.1.2.2.4 Other Nonseismic Transients

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 or relief valves during normal operations if they are caused by plant-specific features or actions or if the valves themselves are unique. If the applicant identifies these types of transients, then the significance of the induced loads on the susceptibility of PLP and PBSC failure can be evaluated (see Figure 1) using, for example, ASME Code, Section XI.[6] Section XI can be invoked to ensure that critical component flaw sizes meet appropriate acceptance criteria such that the failure likelihood is insignificant over the licensing period of the plant. Alternatively, the applicant may describe steps taken, or planned, to mitigate the occurrence of these transients and demonstrate the effectiveness of the mitigation measures over the remaining licensing period to demonstrate that the failure risk associated with the PLP and PBSCs is insignificant.

B.1.2.3 Geometry and Configuration

[6] Applicants should use the most recently approved version of ASME Code, Section XI, for any analysis discussed in this regulatory guide.

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.

Requirements in either ASME Code, Section III or ASME B31.1 govern the design and fabrication of the PLP and PBSCs. In addition, 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. The NRC staff must review and approve any subsequent plant changes with respect to the FSAR primary system geometry and configuration (e.g., removal of piping supports) to ensure that acceptable regulatory margins remain. Therefore, this evaluation only verifies that the FSAR remains applicable.

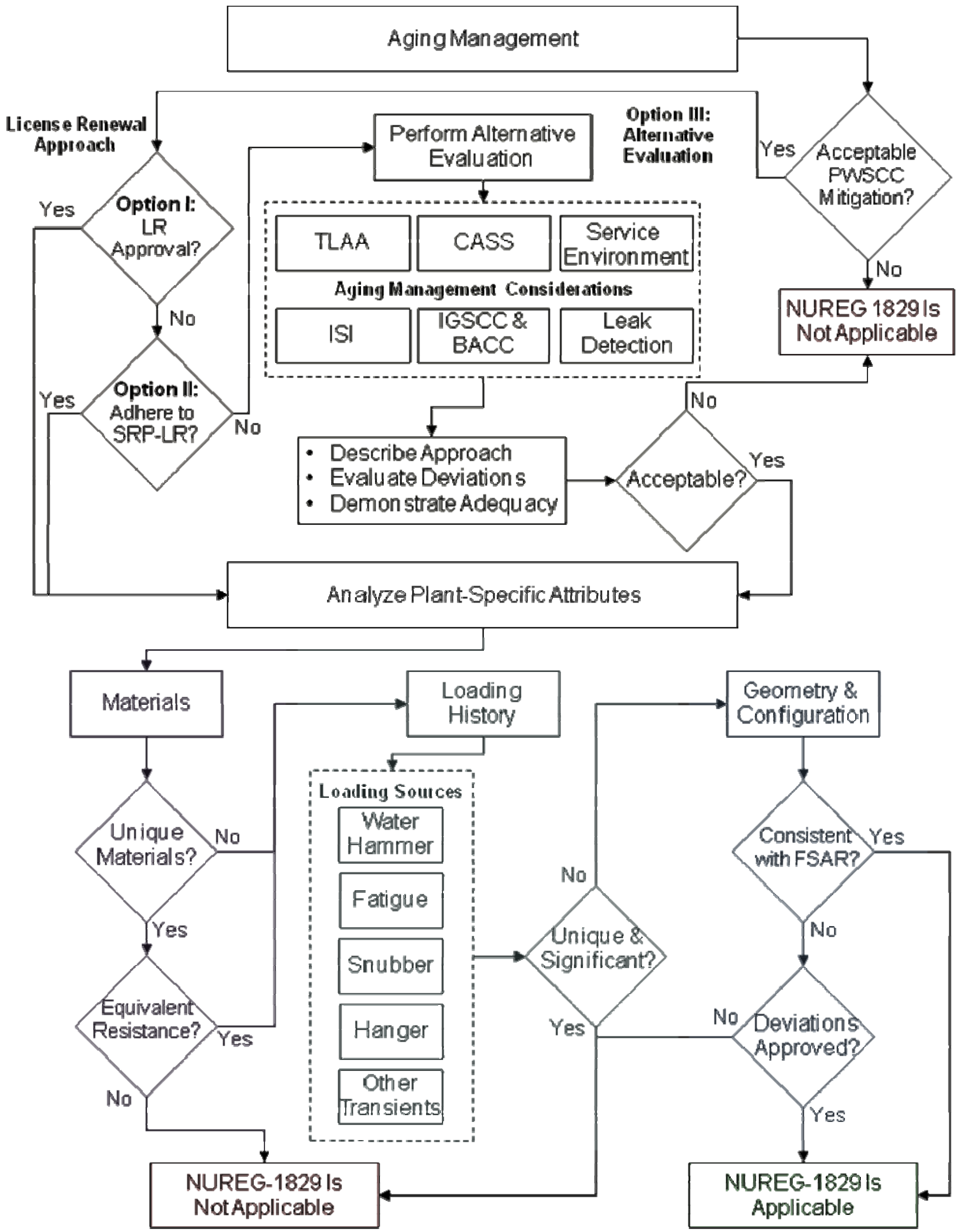

Figure 1. Evaluating plant specific applicability of NUREG-1829

B.1.3 Plant Changes That May Affect Loss-of-Coolant Accident 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 is inconsistent with 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. Therefore, 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. In addition, the applicant should assess the potential impacts on the LOCA frequencies associated with both direct and indirect failures of the PLP and the PBSCs. Age-related degradation can lead to direct failures within the PLP or PBSCs. Indirect failures of the PLP or PBSCs can result from the initial failure in other, nonprimary pressure-boundary-retaining plant systems or components.

B.1.3.1 Plant Changes That May Affect Direct Failure Frequencies

B.1.3.1.1 *General*

As indicated in Section B.1 of this regulatory guide, LOCA frequencies within the PLP and PBSC are a function of several variables, including the materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation associated with each potential failure location. Therefore, this portion of the evaluation should demonstrate that the proposed plant changes under 10 CFR 50.46a do not directly alter any of these critical variables such that the plant's LOCA frequencies increase. Figure 2 (found at the end of this section) illustrates the process for this phase of the evaluation.

B.1.3.1.2 *Evaluation Option I: Effects on NUREG-1829 Variables*

Option I explicitly evaluates the impact stemming from changes related to the following plant variables: materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation. The analysis should initially determine whether the plant change affects any of these variables. For instance, if the PLP and PBSC materials will not be modified, then the plant change is not relevant to this variable. If the change is relevant, the applicant should next assess the significance of the plant change. Significant changes are those that could increase the LOCA frequencies 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 (RS) for extended power uprates (EPUs) (Ref. 29) provides additional guidance related to aspects of these analyses.

Plant changes enacted under the risk-informed revision of 10 CFR 50.46 will most likely impact the service environment, loading history, 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.

B.1.3.1.3 Evaluation Option II: Review Standard for Extended Power Uprates

This option uses guidance and criteria based specifically on the RS for EPUs (Ref. 29) to evaluate the likelihood of changes in the direct failure frequency resulting from the proposed plant change. The RS identifies several evaluations that are pertinent for determining the potential effects of plant changes on the failure of the PLP and PBSCs. The RS also identifies related SRP sections and the applicable regulations addressed by the evaluations and provides other regulatory guidance.

B.1.3.1.3.1 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 applicant may use this evaluation to demonstrate that the RVMSP is unaffected by the proposed plant change. Alternatively, the evaluation may demonstrate that required changes to the RVMSP withdrawal schedule caused by proposed plant changes under 10 CFR 50.46a are acceptable because appropriate material exists to evaluate the integrity of the RPV material to the end of the licensing period.

B.1.3.1.3.2 Pressure-Temperature Limits and Upper-Shelf Energy

Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50 (Ref. 2) establishes pressure-temperature limits (PTLs) to ensure the structural integrity of the ferritic components of the RCPB during normal operations, anticipated operational occurrences, and hydrostatic tests. Plant changes proposed under 10 CFR 50.46a may alter reactor flux and, consequently, the rate of radiation embrittlement of affected materials such that the number of effective full-power years (EFPYs) over the licensing period is affected. Additionally, plant changes may affect the temperature of the primary system, which may result in changes in the rate of thermal embrittlement for affected materials. The required evaluation addresses both the radiation and thermal embrittlement effects and the impact they have on transition temperature and USE as part of a PTL analysis.

B.1.3.1.3.3 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 will provide information under Section C.1.1 of this regulatory guide to demonstrate how aging management of these materials adheres to the LB. The applicant will also evaluate, under Section C.1.2 of this guide, the significance of plant-specific attributes on the performance of the RCPBMs and components. Therefore, the additional evaluation to demonstrate the plant-specific applicability of the NUREG-1829 results specified in Section C.1.3.1.3.3 should only address the effects of the proposed plant changes on these materials and components.

B.1.3.1.3.4 Pressurized Thermal Shock

The NRC requires a pressurized thermal shock (PTS) evaluation for PWR plants, which 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. Specifically, 10 CFR 50.61, "Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events" (Ref. 2) summarizes existing PTS requirements. Recently, the NRC approved a voluntary, risk-informed alternative to 10 CFR 50.61 (10 CFR 50.61a) which licensees may also adopt (Ref. 30). This rule provides alternate PTS requirements based on updated analysis methods. The provisions of 10 CFR 50.61a reduce the regulatory burden for those PWR licensees who expect to exceed the existing 10 CFR 50.61 requirements before the expiration of their licenses, while maintaining adequate safety. Therefore, this evaluation requires the applicant to describe the PTS method and results that are part of the licensing basis and evaluate the effect of plant changes on the PTS results. The objective of this evaluation is to demonstrate that the risk of RPV failure due to PTS remains acceptably low and is not significantly affected by the proposed plant changes.

B.1.3.1.3.5 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.

If the NRC has granted LBB approval within the PLP, the applicant must analyze the effect of the proposed plant changes on LBB. This analysis should identify and evaluate differences between the updated and existing LBB analysis of record and should specifically address both direct and indirect pipe failure mechanisms. Direct pipe failure mechanisms include water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions. Indirect pipe failure mechanisms include seismic events, system overpressurizations, fires, flooding, and missiles. Failures of systems, structures, and components in close proximity to the PLP represent another possible indirect failure mode. The applicant can demonstrate continued plant-specific applicability of the NUREG-1829 LOCA frequencies if the effects of the proposed plant changes do not significantly impact the existing LBB analysis or results.

B.1.3.1.3.6 Chemical and Volume Control System

In PWR plants, the chemical and volume control system (CVCS) and boron recovery system provide a means 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 ECCS in the event of postulated accidents. The NUREG-1829 results remain applicable to the plant if the effects of the proposed plant changes do not significantly alter the existing water chemistry or corrosion control.

B.1.3.1.3.7 Reactor Water Cleanup System

In BWR plants, the reactor water cleanup system (RWCS) provides a means for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant when necessary. The NUREG-1829 results remain applicable if the effects of the proposed plant changes do not significantly alter existing water chemistry or corrosion control as regulated by the RWCS.

B.1.3.1.3.8 Pressure-Retaining Components and Component Supports

The structural integrity of pressure-retaining components and their component supports (PRC/CS) are designed in accordance with ASME Code, Section III, Division 1, to satisfy the provisions of GDC 1, "Quality Standards and Records"; GDC 2, "Design Bases for Protection against Natural Phenomena"; GDC 4; GDC 14, "Reactor Coolant Pressure Boundary"; and GDC 15, "Reactor Coolant System Design." The objective of this evaluation is to identify any differences in the design-basis calculations resulting from the proposed plant changes. If changes in the design-basis calculations occur, the applicant should calculate and compare the associated margins for normal, upset, emergency, and faulted loading and evaluation to the original design margins. The NRC intends for the applicant to demonstrate that the differences in the original and revised margins are not significant. Additionally, the revised margins should continue to satisfy the ASME Code requirements that are the basis of the original design.

B.1.3.2 Plant Changes That May 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 C.2 of this regulatory guide addresses the seismic risk contribution. As previously discussed, 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. The objective of the analysis of indirect failures 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.

This regulatory guide provides two acceptable options for this analysis. Option I (see Figure 2) 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. If these prior analyses are not significantly affected by the proposed plant change, the results of NUREG-1829 are applicable to the plant. If the prior analyses are affected by the proposed plant change, additional analysis (conducted in accordance with Option II) is used to examine the significance of the plant change on indirect failures. Alternatively, Option II (see Figure 2) explicitly evaluates the impact of the proposed plant changes without relying on prior indirect failure analyses. The method described for Option II is based on existing LBB (Ref. 28) and EPU (Ref. 29) guidance and requirements.

B.1.3.2.1 Impact of Plant Changes on Dynamic Effects

The dynamic effects associated with a pipe rupture in either the 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 evaluation 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. This analysis should specifically address effects on PLP and PBSC supports because support failures may lead to primary pressure boundary failures.

B.1.3.2.2 Impact of Plant Changes on Missile Protection

This evaluation should consider the effect of plant changes on possible PLP and PBSC failures caused by missiles. Missiles could result from in-plant component overspeed failures or high and moderate pressure system ruptures. Examples include missiles that are internally generated within containment, piping failures outside containment, failures of the turbine generator, and failures of the pressurizer relief tank. The objective of this evaluation is to demonstrate the adequacy of the PLP and PBSC missile protection. This evaluation should focus on any changes with respect to an existing, approved missile protection analysis.

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

Alternatively, the analysis may demonstrate that the proposed plant changes do not affect system pressures and component overspeed conditions and that existing overspeed protection features are adequate such that overspeed conditions above the design values are very unlikely. The analysis could also demonstrate that proposed plant changes do not affect the likelihood of missiles.

The applicant may assess the effect of proposed plant changes on the adequacy of existing PLP and PBSC missile protection barriers or systems by identifying any changes in the missile protection measures arising from (or as part of) these proposed changes and demonstrating that the existing or proposed missile protection systems or barriers adequately protect the PLP and PBSC from failures.

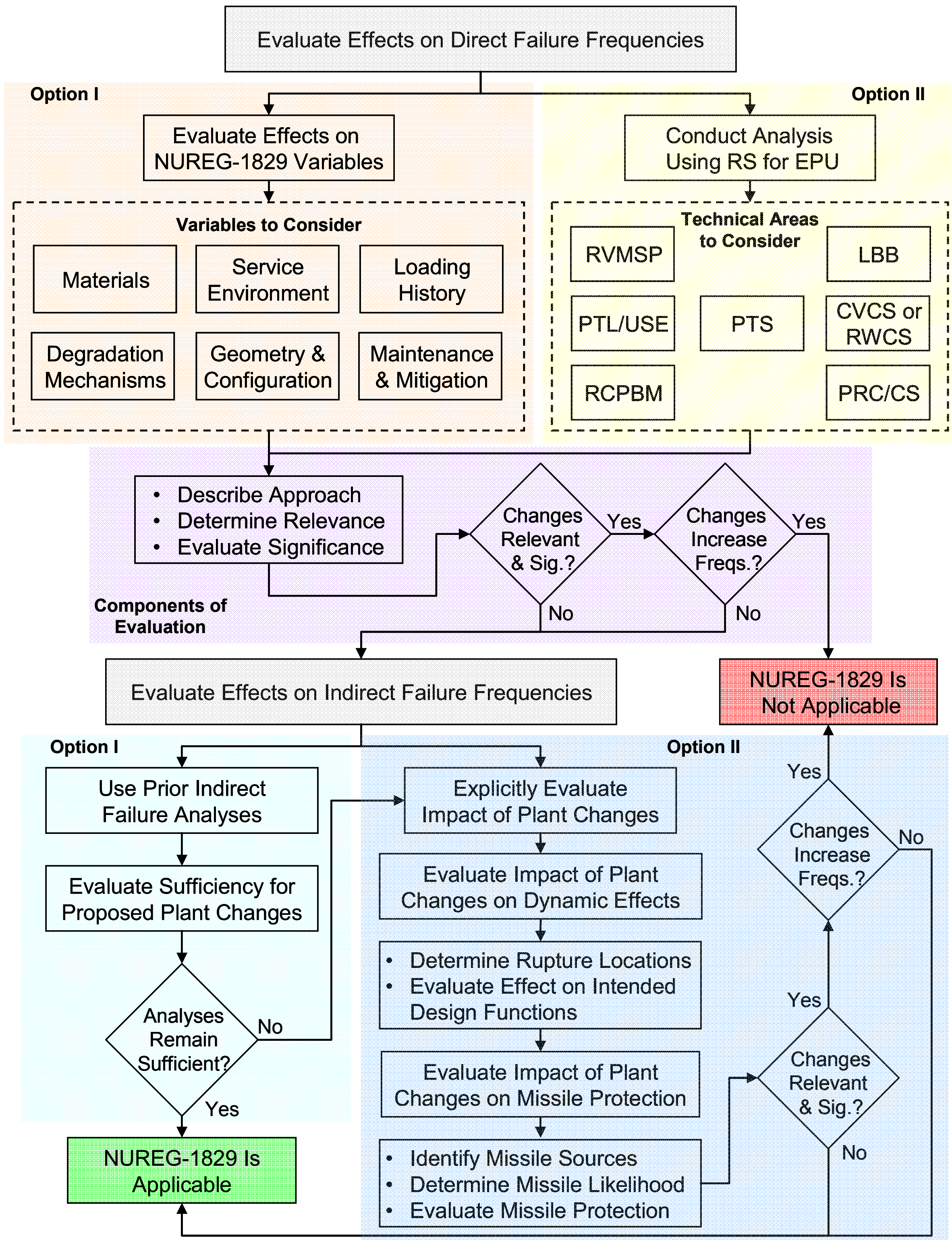

Figure 2. Evaluating the impact of plant changes

B.2 NUREG-1903 Applicability

NUREG-1903 assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. In particular, the study evaluated direct failures of flawed and unflawed primary system pressure boundary components. This section summarizes the general scope, important assumptions, and approach used in the NUREG-1903 analysis and discusses its limitations to support the regulatory positions associated with the analysis to demonstrate that the plant-specific risk of direct PLP and PBSC failures is acceptably smaller than the risk associated with generic, passive system (i.e., nonseismic) LOCAs, as summarized in NUREG-1829.

The following considerations and knowledge of seismic events provided the framework for the NUREG-1903 analysis:

- Seismically induced LOCA frequencies are highly site specific and plant specific.
- Seismic hazard studies and approaches continue to evolve in part because of 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 the failure of major reactor coolant system components or their supports (Ref. 31).

These considerations defined, in part, the scope and approach used in NUREG-1903. For example, they dictated the number and type of plants that were analyzed and the hazard information used in the NUREG-1903 study. Additionally, they allowed the analysis to be confined to the most risk-significant failure modes associated with the PLP.

All plant-specific piping design information used in NUREG-1903 was obtained from LBB analyses that were 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 the 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 and to the specific PLP lines submitted for LBB approval. Similar information is not available for BWR plants.

Seismic stresses and seismically induced LOCA frequencies are proportional to the site-specific seismic hazard (Ref. 32). Furthermore, seismic hazard uncertainties are generally the dominant cause of uncertainties in seismic risk assessments (Ref. 4). Therefore, the seismic hazard is an important contributor to seismic risk. NUREG-1903 uses the update of the revised LLNL seismic hazard curves and uniform hazard spectra (UHS) (Ref. 33). The LLNL results correspond to the 69 sites east of the Rocky Mountains. The analysis used the LLNL study because it is the most recent, comprehensive, and publicly available set of seismic hazard information. However, the development and implementation of seismic hazard assessment methodology has significantly evolved since the publication of the LLNL study (Ref. 33). These recent efforts may impact the seismic hazard curves and UHS associated with the plant sites.

Because of the availability of the seismic hazard information from the LLNL study, NUREG-1903 explicitly analyzed only PWR plants located east of the Rocky Mountains. However, the general approach used in NUREG-1903 is equally applicable to both BWR plants and plants west of the Rockies. 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. Site-specific seismic hazard information can be used to develop more representative plant-specific results as necessary.

The NUREG-1903 report adopted the following approach to evaluate direct piping failures in RCPB piping with diameters larger than the proposed TBS. The hot leg, cold leg, and crossover legs are the only PWR PLP that is larger than the TBS. The evaluation of these legs 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. 34).
- 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 (PGAs) with annual exceedance probabilities of 10^{-5}/yr and 10^{-6}/yr. These earthquake levels were determined using the LLNL mean PGA estimates and extrapolated if necessary for each plant-specific site evaluated.
- Material strength and load resistance parameters were based on mean material properties in the flawed-pipe evaluations. The unflawed-piping analysis used the allowable design stress intensity values, S_m, from Section II of the ASME Code (Ref. 6) to ensure consistency with the unflawed-piping failure criterion used in the analysis.
- The report considered material properties for a carbon steel that incorporated dynamic strain aging effects and for a stainless steel submerged arc weld (SAW) that is susceptible to thermal aging. The analysis assumed that these materials are limiting.

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. 35) was conducted to determine critical flaw sizes corresponding to failure due to seismic events with exceedance probabilities of 10^{-5}/yr and 10^{-6}/yr. 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. 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 to encompass 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 (i.e., 24 of the 26) because these sites generally transmit higher seismic stresses to the piping systems. The study also analyzed two plants founded on soil of varying characteristics. NUREG-1903 (Ref. 4) provides more information on the approach used to evaluate direct piping failures.

B.2.1 General Considerations

For the cases studied in NUREG-1903, large circumferential flaws (i.e., crack lengths approximately 80 percent of the pipe circumference) fail under rare seismic events when the flaw depth is a significant percentage of the wall thickness. Specifically, for a 10^{-5}/yr seismic event, the critical flaw depth is approximately 35 percent of the wall thickness, while for a 10^{-6}/yr seismic event, the critical flaw depth is approximately 25 percent of the wall thickness for the limiting thermally aged stainless steel welds. It is unlikely that such extensive flaws would exist within the PLP if a rare seismic event were to occur. However, because the NUREG-1903 analysis was not intended to be bounding (e.g., the analysis did not consider thermal embrittlement of CASS and other materials), the actual critical flaw depth for a specific plant may be smaller than these estimates. Therefore, this guidance provides various approaches that an applicant can use to estimate the critical flaw size within the PLP for a rare seismic event. Figure 3, located at the end of this section, illustrates the process for this phase of the evaluation.

B.2.1.1 Bounding Analysis

One approach to this seismic evaluation is to demonstrate that the subject plant is bounded by the NUREG-1903 results. In this bounding analysis, the applicant should demonstrate that the plant-specific PLP stresses, materials, material properties (including any aging-related property changes), and site-specific hazard information individually falls within, or is bounded by, the ranges considered in NUREG-1903. Additionally, the plant-specific combination of PLP stresses, materials, material properties, and site-specific hazard information should also be bounded by evaluations within NUREG-1903. If these conditions are satisfied, the bounding critical flaw depth calculated in NUREG-1903 (i.e., approximately 35 percent for a 10^{-5}/yr seismic event or 25 percent for a 10^{-6}/yr seismic event for thermally aged stainless steel weld properties) will also bound the value that would be calculated for the specific plant.

B.2.1.2 Direct Analysis

An alternate analytical approach is to directly calculate the plant-specific critical flaw sizes. This approach is applicable if the existing NUREG-1903 analyses do not bound the plant's conditions or if the applicant wants to demonstrate that the plant-specific critical flaw sizes are larger than the bounding values in NUREG-1903. The objective of the plant-specific flawed piping analysis is to determine critical flaw depths for long surface flaws (i.e., $\theta/\pi = 0.8$) that correspond to a seismically induced failure frequency of 10^{-6}/yr 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}/yr. This analysis is used 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. Appendix A to this regulatory guide contains detailed information from NUREG-1903 that an applicant can use for a plant-specific evaluation.

B.2.1.2.1 <u>Analysis Requirements</u>

The analysis scope is defined by identifying critical locations within the PLP for subsequent evaluation. Because only those piping systems having an inner diameter greater than the TBS are potentially applicable, the scope is effectively restricted to the PLP. The analysis next identifies critical locations within the piping system. The critical locations have the combination of the highest normal plus seismic stresses and the lowest material toughness properties that result in the smallest critical flaw sizes. These locations can likely be identified without detailed knowledge of the actual material properties and stresses within the PLP. However, subsequent steps may require that refined information. The ASME Code or other design stress and material information can be used to aid in the initial selection of the critical locations.

However, a location's susceptibility to degradation mechanisms that can lead to cracking (e.g., IGSCC, PWSCC) is an important factor in identifying the critical locations. Additionally, 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 are also important considerations when selecting critical locations.

B.2.1.2.2 Component Stresses

This regulatory guide provides three options for determining the component level stresses resulting from the seismic loading. Options I and II, respectively, allow for the use of either the NUREG-1903 results directly or a calculation based on the NUREG-1903 approach. Option III allows the component stresses to be determined from direct analysis. Options I and II are simpler and therefore are intended to be more conservative than Option III. Option III is significantly more complex. The level of complexity associated with Option III will also increase as fewer conservative assumptions are employed to develop more realistic or BE results.

B.2.1.2.2.1 Option I: NUREG-1903 Results

NUREG-1903 analyzes 26 PWR plants east of the Rocky Mountains. This option is only available to the specific plants analyzed in NUREG-1903. Appendix A lists these plants and provides the applicable design SSE PGAs. 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 staff then extrapolated the SSE-level stresses to component stresses associated with a 10^{-6}/yr seismic event using the approach described in Sections 4.5.1 and 4.5.2 of NUREG-1903 (Ref. 4). Appendix A to this regulatory guide also lists the locations, relevant LBB information, and associated 10^{-6}/yr seismic stresses for each plant analyzed in NUREG-1903.

B.2.1.2.2.2 Option II: NUREG-1903 Scale-Factor Method

If the NUREG-1903 analysis did not evaluate the plant's limiting normal operating plus seismic component stresses, Option II uses the scale-factor method described in NUREG-1903 to determine the component stresses. Appendix A to this regulatory guide provides scale factors for the seismic hazard associated with all PWR plant sites. The seismic hazard curve and UHS should represent the ground-motion response at the plant site out to a 10^{-6}/yr probability of exceedance. The analysis should also appropriately address uncertainties when determining the site-specific seismic hazard information or when justifying the use of existing hazard information.

B.2.1.2.2.3 Option III: 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), Option III allows the applicant to determine the component stresses at the critical locations using direct analysis. The objective of this analysis is to determine the peak axial seismic stresses at the limiting locations. The applicant will then use these stresses to determine the critical flaw depths at these locations.

The site-specific hazard information used in this analysis should reflect all current requirements and updates to the seismic hazard models (e.g., as required by American National Standards Institute/American Nuclear Society (ANSI/ANS) 58.21, "External Events PRA Methodology" (Ref. 34)). The foundation properties should use an appropriate model of the soil and rock properties that are applicable to the site. 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. ANSI/ANS-58.21 (Ref. 34) provides more information and details related to dynamic modeling considerations.

The model of the PLP within the reactor building dynamic model may be either a detailed or a simplified PLP model. The simplified PLP model should incorporate appropriate mass and stiffness characteristics to represent the overall plant behavior. If a detailed PLP model is chosen, the stresses at the limiting locations are used directly in subsequent fracture mechanics calculations. If the applicant chooses a simplified PLP model, the output from the overall reactor building dynamic model (i.e., time histories or response spectra at PLP support points) at the limiting locations should be used as input to a separate, detailed PLP model. The applicant should then use the stresses calculated from this separate, detailed PLP model within subsequent fracture mechanics calculations.

B.2.1.2.3 *Material Properties*

The NUREG-1903 analysis assumed toughness and strength properties representative of carbon steel base metals and welds, as well as stainless steel submerged arc weld (SS-SAW) material, both with and without adjustment for thermal aging. The NUREG-1903 analysis derived the baseline SS-SAW J-R curve (i.e., without thermal aging effects) from a statistical analysis of data in the PIFRAC pipe fracture database (Ref. 36). No statistically significant differences exist between the toughness of shielded metal arc welds (SMAWs) and 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 materials was also adjusted to account for dynamic rate and cyclic loading effects that occur during an earthquake (Ref. 4). NUREG-1903 provides additional guidance for addressing the effects of elevated loading rates on material toughness (i.e., J-R curve) properties. The thermally aged SS-SAW J-R curve properties were obtained from a previous evaluation of this effect (Ref. 37). Finally, the NUREG-1903 evaluation used a modified J-R curve that more realistically predicted the results of large-scale piping tests (Ref. 38). This procedure was used to develop modified Z-factor equations (see Appendix A to this guide) for the limiting materials evaluated in NUREG-1903.

The material properties should also reflect the inherent uncertainty and variability in those properties. For material toughness, uncertainty can be addressed by obtaining a statistically significant number of J-R curves that represent the limiting material and calculating the mean minus one standard deviation J-R curve. Alternatively, the applicant can choose an appropriate J-R curve from the ASME Code if it can demonstrate that the J-R curve selected is more conservative than that expected for the limiting material after accounting for uncertainties in the properties.

Similarly, for material strength properties, uncertainty can be considered by obtaining a statistically significant number of stress-strain curves that represent the limiting material and calculating the mean minus one standard deviation stress-strain curve. Alternatively, the applicant may choose an appropriate stress-strain curve from the ASME Code if it can be demonstrated that the stress-strain curve selected is more conservative than that expected for the limiting material after accounting for uncertainties in the properties.

The analysis can address variability in J-R and stress-strain properties by evaluating the impact that alloying, compositional, and microstructural differences have on the measured properties. The alloying compositional and microstructural differences should reflect the range of allowable materials conditions and represent the variability induced by fabrication or processing methods applied within the plant. The analysis can also utilize J-R and stress-strain properties from the ASME Code to account for material variability, if the applicant demonstrates that the ASME Code properties are more conservative than the properties (i.e., properties after accounting for variability) expected for the limiting plant materials.

The applicant can then compare the selected strength and toughness properties to the appropriate properties used in NUREG-1903. If the applicant cannot demonstrate that the material properties used in the NUREG-1903 analysis represent or conservatively bound the selected properties, the applicant should utilize plant-specific properties in the analysis. The applicant can select the plant-specific properties from either representative strength and toughness properties or material properties allowed by the ASME Code. The guidance in this section and Section C.2.1.2.3 are also applicable to developing these properties.

B.2.1.2.4 NUREG-1903 Critical Surface Flaw Analysis

This regulatory guide provides two options for determining the critical surface flaw size using the approach outlined in NUREG-1903. The first, and simplest, option allows the applicant to directly determine the surface flaw size from the NUREG-1903 results without any additional calculations, so long as several conditions are satisfied. The second option is applicable if all the conditions required for the first option are not satisfied. This option requires that the applicant conduct a plant-specific analysis that follows the calculation steps detailed in NUREG-1903 (see Appendix B to this regulatory guide) to determine the critical surface flaw size.

B.2.1.2.4.1 Option I: NUREG-1903 Surface Flaw Results

If the material properties are bounded by those used in NUREG-1903 and the axially oriented normal operating plus 10^{-6}/yr seismic stress (determined in Section C.2.1.2.2) is less than 35 kilopounds per square inch (ksi), the applicant can determine plant-specific critical flaw sizes directly from NUREG-1903. If the total normal operating plus seismic stress value is between 10 and 35 ksi, the ratio of the critical flaw depth to the component thickness for a surface flaw having a length of $\theta/\pi = 0.8$ can be found using Figure 4-15 in NUREG-1903 for austenitic pipe. 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. If the total stress is greater than 35 ksi, a plant-specific analysis will be needed to determine the critical flaw depth.

B.2.1.2.4.2 Option II: Plant-Specific Analysis

A plant-specific critical flaw size analysis will be necessary if either of the following conditions apply:

- The material properties used in the NUREG-1903 analysis are not applicable to the plant-specific materials at the limiting locations.
- The normal operating plus 10^{-6}/yr seismic stresses (Section C.2.1.2.2) are greater than 35 ksi at each critical location.

The applicant may also elect to conduct a plant-specific analysis even if both of the above conditions are met. Such an analysis may be used if the applicant wishes to demonstrate that the plant-specific critical flaw sizes are larger than the value determined in the NUREG-1903 analysis.

Section 4.5.2 of NUREG-1903 (Ref. 4) provides one acceptable plant-specific analysis for determining the critical flaw sizes for a 10^{-6}/yr seismic event. In addition, Appendix B to this regulatory guide describes step-by-step procedures for conducting this analysis and provides a sample calculation. This approach is consistent with the allowable flaw size determination described in Appendix C to ASME Code, Section XI, although no additional margin (i.e., structural factor of 1.0) is applied to the seismic stresses.

Part of this plant-specific analysis (Section C.2.1.2.4.2) requires a potential adjustment to correct for material plasticity if the applicant used elastic calculations to determine the normal operating plus 10^{-6}/yr seismic stress (i.e., total stress). Total stress values less than the material yield strength determined in Section C.2.1.2.3 do not require additional correction. However, if the total stress from an elastic analysis is greater than the material yield strength, the applicant should multiply the total stress 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 from elastic analyses. This failure criterion was developed from seismic testing of unflawed nuclear piping components (Ref. 39).

Another component of the Section C.2.1.2.4.2 analysis determines a correction for the Z-factor. The NUREG-1903 analysis calculated revised Z-factors to account for seismic loading, dynamic strain aging, and thermal aging effects, as appropriate for the materials evaluated in NUREG-1903. Appendix A to this guide provides these revised Z-factors. The applicant can also determine the Z-factor for the nominal pipe diameter at each critical location using the equations supplied in NUREG-1903 for materials not evaluated in NUREG-1903. Section B.2.1.2.3 provides more information on the Z-factor calculation in NUREG-1903.

B.2.1.2.5 *ASME Code, Section XI, Critical Surface Flaw Analysis*

If this analysis described in Section C.2.1.2.5 of this regulatory guide is performed, 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. This analysis uses the structural factors and Z-factors prescribed by the ASME Code and not the BE factors employed in Section C.2.1.2.4. This analysis should also use the normal operating plus SSE stresses determined in accordance with the ASME Code requirements for Service Levels A and C/D loading, respectively. The applicant should not use the total normal plus 10^{-6}/yr seismic stresses determined for the Section C.2.1.2.4 analysis in the Section C.2.1.2.5 analysis. Additionally, Section C.2.1.2.5 allows the use of either representative material properties or those material properties allowed by the ASME Code. However, the material properties should be chosen such that all requirements in Section XI of the ASME Code are met.

B.2.1.2.6 *Seismic Frequency Contributions*

Section C.2.1.2.6 provides three separate criteria for demonstrating that the failure frequency of the PLP due to seismic loading is significantly less than the failure frequency for normal operational loading and plant transients as evaluated in NUREG-1829. If none of these criteria can be satisfied, the seismic failure frequency is unacceptable, and plant changes cannot be pursued under the risk-informed revision of 10 CFR 50.46. However, if any one of these three 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. The required technical justification of demonstrating the acceptability of the ISI programs is increasingly rigorous for each successive criterion as the critical flaw depths decrease. The following paragraphs provide more information on each criterion.

The first criterion is that the critical flaw depths calculated in Section C.2.1.2.4 are greater than 25 percent of the through-wall thickness at each limiting location. There is a high probability that inspections will detect a flaw this large before the critical flaw depth is reached. Therefore, the applicant need only confirm that inspection is conducted at each limiting location and that the associated ISI programs satisfy either ASME Code, Section XI requirements (including Appendix VIII), or other applicable requirements associated with NRC-approved inspection programs (e.g., risk-informed ISI). Limiting locations that are not currently inspected should be included in the ISI program in order to enable changes under 10 CFR 50.46a. However, if this criterion is met, the NRC does not intend that applicants demonstrate that current or planned ISI programs (i.e., those associated with approved AMPs, ASME criteria, or other regulatory requirements) are sufficient to reliably detect such flaws.

If Criterion 1 is not satisfied, the critical surface flaw depths calculated in Sections C.2.1.2.4.2 (i.e., NUREG-1903 approach) and C.2.1.2.5 (i.e., ASME Code, Section XI, approach) are compared at each limiting location. If the critical flaw depths are greater than the ASME Code, Section XI, flaw acceptance criteria, then Criterion 2 is satisfied. 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. The ASME Code requires that a flaw will be dispositioned before reaching a size that would lead to failure under the presumed seismic event. Because the ASME Code requirements govern flaw disposition under this criterion, Section C.2.1.2.6 requires that the applicant confirm that the limiting locations are inspected (or these locations are added to existing inspection requirements) and that the ISI programs satisfy the applicable ASME Code requirements. Any relaxation of these requirements or use of other NRC-approved inspection requirements that are less conservative than ASME Code requirements will not sufficiently demonstrate that flaws will be appropriately detected and dispositioned under this criterion.

The third criterion requires demonstration that the ISI programs are sufficient for detecting flaws before reaching the critical flaw depths calculated in Section C.2.1.2.4.2. Section C.2.1.2.6 provides minimum requirements for ISI programs. Once again, all limiting locations should be inspected. Detectability limits should then be established. These detectability limits should represent flaws that can be reliably detected and accurately sized on representative mockups by the applicable nondestructive examination method employed at the limiting locations. These detectability limits should be less than the critical flaw sizes calculated in Section C.2.1.2.4.2. Additionally, Section C.2.1.2.6 requires justification that these flaws can be reliably detected in practice. The applicant may use qualification results and operational experience for applicable ISI techniques to support this justification. Furthermore, Section C.2.1.2.6 requires that the inspection periodicity be sufficient to detect flaws before reaching the critical flaw sizes calculated in Section C.2.1.2.4.2. The applicant may determine inspection periodicity using ASME Code, Section XI, Appendix C or other applicable requirements.

B.2.1.3 Stress-Corrosion Cracking Mitigation

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 or structural characteristics within these regions. For instance, 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 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 within the susceptible region.

Additionally, preexisting SCC flaws in these susceptible regions may not have been repaired before SCC mitigation. Each SCC mitigation technique typically has an allowable maximum flaw depth that must be considered when designing and implementing the technique. Flaws existing before the mitigation is applied are required to be less than this maximum-allowable flaw depth (Ref. 11). 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, PWSCC mitigation had not been implemented industrywide. 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 only confirms in Sections C.1.1.1or C.1.1.2.3.4 that SCC management satisfies applicable industry, ASME Code, and regulatory requirements to demonstrate the plant-specific applicability of the NUREG-1829 results.

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 demonstrates in Section C.2.1.3 that the seismic failure frequency associated with SCC-susceptible PLP locations is insignificant. Section C.2.1.3 identifies that it is acceptable to demonstrate that the minimum structural factors required by ASME Code, Section III, are retained for Service Level C/D, or SSE, loading. This analysis should demonstrate that the ASME Code margins are retained for assumed flaws that are part of the design basis, or the maximum allowable flaws, associated with the particular mitigation technique. References 11, 20, and 40 discuss this approach more fully. The basis for the acceptability of this approach is that the applicant will demonstrate that mitigation has restored the PLP at each limiting location to the original design margins and that the ISI plan is sufficient to detect indications before they reach a size that could lead to failure under design-basis conditions.

If the ASME structural factors are not met, the applicant can determine whether the maximum allowable premitigation flaw (Ref. 11) results in any crack growth or failure during the 10^{-6}/yr seismic event using the analysis described in Sections C.2.1.2.3 and C.2.1.2.4. The fracture analysis should not credit any compressive stresses induced by mitigation because they are secondary stresses. This analysis should also neglect other secondary stresses. Alternatively, the applicant may also directly assess the failure propensity of the limiting location using the following steps:

1. Create a detailed PLP model that contains the maximum allowable premitigation flaw.
2. Simulate the mitigation technique to predict the residual stress distribution at that location.
3. Simulate the 10^{-6}/yr seismic event to determine the component stresses.
4. Conduct a flaw instability analysis (as described in Sections C.2.1.2.3 and C.2.1.2.4) to determine whether significant crack growth or failure occurs under seismic loading.

This last option allows the applicant some credit for residual and other secondary stresses at the expense of a more complicated and complete analysis.

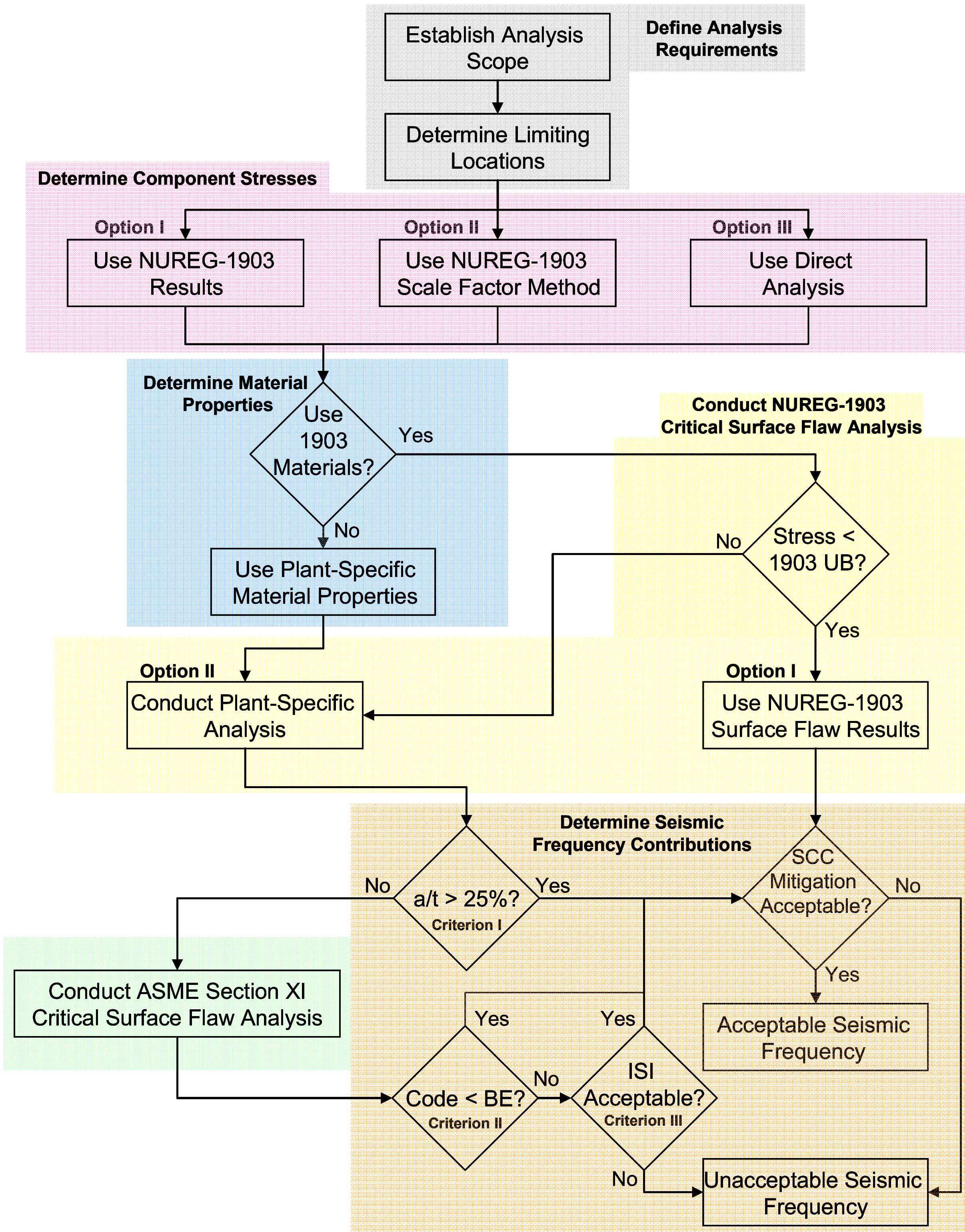

Figure 3. Evaluating seismically induced risk of direct PLP failures

C. REGULATORY POSITION

C.1 NUREG-1829 Applicability

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

- adherence to the LB, including associated regulatory guidance (e.g., Generic Letter 88-01, Supplement 1 (Ref. 19)), and industry programs (e.g., aging management, water chemistry, SCC mitigation) related to inspection or other mitigation of age-related degradation, and
- plant-specific attributes that may increase LOCA frequencies compared to the NUREG-1829 results.

C.1.1 Aging Management

Figure 1 provides a schematic describing an acceptable method for determining the applicability of the NUREG-1829 results to a specific plant.

C.1.1.1 Primary Water Stress-Corrosion Cracking

All applications for PWR plants should address PWSCC.

C.1.1.1.1 *<u>Primary Water Stress-Corrosion Cracking Location and Mitigation</u>*

Locations for evaluation are limited to the PLP and PBSC. The applicant should do the following:

- Describe the ISI plans and mitigation strategies for all applicable DMWs.
- Identify the type of mitigation used for all applicable DMWs.
- Describe the applicable codes or standards used in the design, fabrication, and implementation of the mitigation.
- Identify and evaluate the effect of any deviations from the applicable codes or standards.
- Complete mitigation of PLP and PBSC DMWs before enacting any plant changes allowed under the risk-informed revision to 10 CFR 50.46 or demonstrate that the failure risk of unmitigated DMWs is insignificant.

C.1.1.1.2 *<u>Primary Water Stress-Corrosion Cracking Inservice Inspection Program</u>*

The NRC staff expects the applicant to conduct the ISI program associated with DMWs in accordance with ASME Code Case N-770 (Ref. 11) and any conditions that may be imposed in 10 CFR 50.55a. Therefore, the applicant should do the following:

- Identify deviations from this ASME Code case, associated NRC conditions, and applicable ASME Section XI,[7] Appendix VIII requirements.
- Evaluate the effects of these deviations on the structural integrity and failure likelihood of the DMWs.

[7] The applicant should use the most recently approved version of ASME Section XI to perform analyses described in this regulatory guide.

C.1.1.2 Aging Management Programs and Time-Limited Aging Analysis

All applicants should demonstrate that the plant's service environment, inspection, and maintenance activities comply with the LB and are consistent with industry guidelines and practice (i.e., programs) that address aging management strategies. The GALL Report (Ref. 12) and the SRP-LR (Ref. 13) describe acceptable methods and acceptance criteria for the AMPs. Applicants may choose one of the three options described below, as appropriate, to demonstrate consistency with the LB. Applicants can also propose alternative methods and acceptance criteria. If alternative methods are proposed, the staff will review each deviation from the GALL Report and SRP-LR guidance to determine the acceptability of this method in managing age-related degradation.

C.1.1.2.1 Evaluation Option I: License Renewal Approval

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 LB (Figure 1).[8] 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.

C.1.1.2.2 Evaluation Option II: License Renewal Submittal

Applicants that have applied for LR, but have not been granted acceptance, should do the following:

- Describe how the AMPs for the PLP and PBSCs adhere to the GALL Report and SRP-LR guidance (Figure 1).
- Identify and describe any AMPs that deviate from SRP-LR guidance.
- Demonstrate how these AMPs satisfy the applicable regulatory requirements associated with the LB.

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 60-year LR period.

C.1.1.2.3 Evaluation Option III: Alternative Evaluation

Applicants that have not applied for LR should perform an alternative evaluation (Figure 1) to provide the basis for the plant's adherence to the LB. This alternative evaluation can be structured similarly to an LR application. That is, the applicant should demonstrate that all applicable regulatory requirements associated with the PLP and PBSCs are met. Additionally, the applicant should demonstrate that relevant AMPs have been implemented (or will be implemented before adoption of 10 CFR 50.46a) to adhere to the GALL Report and SRP-LR guidance related to the PLP and PBSCs. Several specific aging management considerations (Figure 1) also apply to the PLP and PBSCs, and should be explicitly addressed in this alternative evaluation. In general, for each alternative evaluation topic, the applicant should describe the aging management approach, evaluate any deviations with the GALL Report or SRP-LR requirements, as applicable, and demonstrate the adequacy of the existing (or

[8] 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.

proposed) AMP (Figure 1). The following sections discuss the specific considerations associated with each evaluation topic.

For both BWR and PWR plants, applicants should consider AMPs associated with CASS components and other piping materials that are susceptible to thermal embrittlement, the ISI plan and procedures, and the primary and secondary system water chemistries.

C.1.1.2.3.1 Cast Austenitic Stainless Steels

In the CASS evaluation, the applicant should do the following:

- 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 14.
- Indicate and describe the AMP that is followed for those components described as "potentially susceptible" in Reference 14.
- Evaluate any deviations with the GALL Report or SRP-LR requirements, as applicable.
- Demonstrate the adequacy of the existing (or proposed) AMP.

C.1.1.2.3.2 Inservice Inspection

In the ISI evaluation, the applicant should 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. This description should do the following:

- Identify the PLP welds that are inspected under the ISI program.
- Highlight the inspection periodicity of these welds.
- Note the inspection procedures.
- Outline the acceptance criteria.
- Discuss the quality assurance provisions.
- Confirm that the ISI program adheres to all applicable codes and standards, staff positions, or approved inspection procedures, as appropriate.

The description should also identify and justify deviations from ASME Code, Section XI (including Appendix VIII), requirements; an NRC-approved, risk-informed ISI plan; or other governing requirements, as applicable.

C.1.1.2.3.3 Service Environment

Because the elicitation considered the expected effects related to the service environment, the applicant's evaluation should demonstrate that the plant-specific service environment is maintained within an acceptable range that adheres to the LB and follows applicable industry guidance. Specifically, for the PLP and PBSC system temperatures and water chemistry evaluation, the applicant should do the following:

- Confirm that the plant is following the guidelines that are appropriate for the PLP and each PBSC.
- Confirm that applicable regulatory requirements are satisfied.
- Describe the quality assurance measures adopted to ensure compliance with the temperature and 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.

C.1.1.2.3.4 Intergranular Stress-Corrosion Cracking

For BWR plants, the applicant should demonstrate acceptable management of IGSCC. The applicant should do the following:

- Describe ISI programs and mitigation strategies for all applicable stainless steel piping (and welds) that are susceptible to (or are currently mitigated for) IGSCC.
- Identify the type of mitigation used for all applicable components.
- Discuss the applicable codes and standards used in design, fabrication, and implementation of the mitigation strategies.
- Indicate and describe any deviations from the applicable codes and standards; Generic Letter 88-01 staff positions (Ref. 19); ASME Code, Section XI, Appendix VIII, requirements; or BWRVIP-75 (Ref. 20) inspection procedures.
- Evaluate the effects of any deviations listed above on the structural integrity and failure likelihood of IGSCC-susceptible components.

C.1.1.2.3.5 Boric Acid Corrosion Control

For PWR plants, the applicant should demonstrate that acceptable BACC programs are being implemented. As indicated in Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," dated March 17, 1988 (Ref. 41), 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:

- 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,
- procedures for locating small coolant leaks (i.e., leakage rates at less than technical specification limits),
- methods for conducting examinations and performing engineering evaluations to establish the impact on the RCPB when leakage is located, and
- corrective actions to prevent recurrences of this type of corrosion.

  Applicants should also ensure the following:
- commitments made in response to Generic Letter 88-05 are being implemented,
- current inspections satisfy the requirements of 10 CFR 50.55a(g)(6)(ii)(D) and 10 CFR 50.55a(g)(6)(ii)(E), and
- any other BACC program enhancements to provide early detection and prevention of leakage resulting from through-wall cracking from passive system RCPB components are noted (see Section B.1.1.2.3.5 for more information).

C.1.1.2.3.6 Time-Limited Aging Analysis

Additionally, the Option III evaluation should describe the TLAA of fatigue and leak-detection procedures in these components. 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 do the following:

- Describe the procedures that are used to determine the cumulative usage factors for fatigue and demonstrate how these procedures satisfy the requirements of 10 CFR 54.21(c)(1) over the licensing period.
- Consider, in the fatigue analysis, 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.[9]
- Address the impact of environmental fatigue.

C.1.1.2.3.7 Leak Detection

Finally, the Option III evaluation should demonstrate that leak-detection capabilities are adequate such that the NUREG-1829 results are applicable. Regulatory Guide 1.45, Revision 1 (Ref. 27), provides one acceptable method for demonstrating that the plant's leak-detection capabilities are adequate. Alternatively, the applicant should demonstrate that the plant's leak-detection capabilities comply with technical specification limits for identified and unidentified leakage. This demonstration should address, as further described in Regulatory Guide 1.45, Revision 1 (Ref. 27), the types of leakage, leakage separation, methods for monitoring leakage and identifying its source, monitoring system performance, seismic qualification, and leakage management.

C.1.2 Plant-Specific Attributes

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. The important plant-specific attributes to consider are related to the materials, loading history, geometry and configuration, service environment, and maintenance and mitigation strategies (Figure 1) associated with the PLP and each PBSC. The screening method that is subsequently described provides one acceptable method for demonstrating that the plant-specific LOCA frequencies are consistent with the NUREG-1829 estimates.

C.1.2.1 Materials

The applicant should evaluate the effects of materials on the plant-specific LOCA frequencies if the PLP or PBSCs contain either unique materials or common materials in unique locations (Figure 1). One example is the use of Alloy 600 component safe-ends rather than stainless steel safe-ends. The applicant should discuss the existence of such materials by either of the following:

- Describing the location and service conditions associated with either unique materials or common materials in unique locations.
- Documenting that no such materials exist within the PLP or PBSCs.

If either unique materials or locations exist, the applicant should do the following:

- Identify and describe known degradation mechanisms that have been observed in either operating experience or representative laboratory testing.
- Assess the impact of the loading history and environment on these degradation mechanisms and describe applicable AMPs for that material or location or both as appropriate.

[9] 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.

- Demonstrate that the AMPs will acceptably mitigate the applicable degradation mechanisms.

C.1.2.2 Loading History

The plant-specific evaluation should ensure that the loading history associated with the PLP and PBSCs is comparable to industrywide conditions. Therefore, the applicant addresses the likelihood and significance of effects associated with transients, or other unique loads, that depend on or result from the plant-specific configuration. Specifically, the applicant should consider the following loading sources (Figure 1): water hammer, fatigue, snubber failure, rigid support (i.e., hangers and struts) misadjustments, and any other nonseismic transients. More details of relevant considerations for each of these loading sources follow.

C.1.2.2.1 *Water Hammer*

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 take the following actions:

- Assess historical frequencies of water hammer events affecting the PLP or PBSC.
- Evaluate operating procedures and conditions and demonstrate that they are effective in precluding water hammer.

Alternatively, the applicant can demonstrate the following:

- 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.
- Measures used to abate water hammer frequency and magnitude have been effective over the licensing period of the plant.

C.1.2.2.2 *Fatigue*

The applicant should ensure that the potential for pipe rupture due to thermally induced, mechanically induced, and flow-induced fatigue is unlikely within the PLP or PBSCs. Specifically, the applicant should do the following:

- Demonstrate that these systems do not have a history of fatigue cracking or failure.
- Demonstrate that adequate mixing of high- and low-temperature fluids occurs in the PLP so that the potential for fatigue cracking resulting from cyclic thermal stresses is insignificant.
- Demonstrate that the potential for vibration-induced fatigue cracking or failure is insignificant.

The analysis should also address the impact of environmental effects on the fatigue life curves, as discussed in Section C.1.1.2.

C.1.2.2.3 *Rigid support Misadjustments and Snubber Failures*

Rigid support misadjustments can significantly alter the PLP design stresses. Accordingly, the applicant should describe how proper rigid support adjustment is verified during installation or reinstallation activities. This description should do the following:

- Document applicable codes and standards followed during rigid support adjustment.
- Document associated quality assurance provisions.

The failure of any snubbers that remain within the PLP could also lead to higher pipe stresses than considered in the PLP design. 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.

C.1.2.2.4 Other Nonseismic Transients

This evaluation assesses the impact on PLP and PBSC failures from other plant-specific significant, nonseismically induced transients that have not been previously addressed. The applicant should identify applicable transients based on plant-specific operating experience (see Figure 1), and do the following:

- Assess the significance of the induced loads from each transient on the failure susceptibility of PLP and PBSC components over the licensing period of the plant, or describe steps taken, or planned, to mitigate these transients.
- Evaluate the effectiveness of the mitigation in preventing these transients over the plant's licensing period.

C.1.2.3 Geometry and Configuration

The applicant should 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). If deviations exist, the applicant should verify that the NRC staff has reviewed and approved these deviations.

C.1.3 Plant Changes That May Affect Loss-of-Coolant Accident Frequencies

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. Figure 2 illustrates an acceptable method for evaluating the impact of plant changes on direct and indirect failure frequencies. More guidance on this evaluation follows.

C.1.3.1 Plant Changes That May Affect Direct Failure Frequencies

C.1.3.1.1 General

The applicant should analyze 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 materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation that are associated with the PLP and PBSC.

C.1.3.1.2 *Evaluation Option I: Effects on NUREG-1829 Variables*

This option explicitly evaluates the impact stemming from changes related to the materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, and maintenance and mitigation. The applicant should do the following (Figure 2):

- Describe the approach used in the analysis.
- Determine whether the plant change affects either the materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, or maintenance and mitigation.
- Assess the significance of the effect of the plant change, as appropriate, on the materials, service environment, loading history, age-related degradation mechanisms, geometry and configuration, or maintenance and mitigation.
- Assess the effect of plant changes on the emergence of new, or previously unobserved, degradation mechanisms.

The review standard for EPUs (Ref. 29) provides additional guidance related to the aspects of these analyses that the applicant should consider.

C.1.3.1.3 *Evaluation Option II: Review Standard for Extended Power Uprates*

This option uses guidance and criteria based specifically on the review standard for EPUs (Ref. 29) to evaluate the likelihood of changes in the direct failure frequency resulting from the proposed plant change. Evaluations should address the effects of the changes on the RVMSP; the PTL/USE, PTS, RCPBMs, LBB, CVCS, or RWCS; and the PRC/CS. As with Option I, each evaluation should generally consist of the following (Figure 2):

- a description of the approach,
- an assessment of the relevance of the plant change to the particular evaluation area or program,
- a determination of the significance of the plant change if the change is relevant, and
- an assessment of the effect of the change on the emergence of new, or previously unobserved, degradation mechanisms.

The review standard for EPUs (Ref. 29) provides more detail on the related SRP sections, the applicable regulations addressed by the evaluations, and other regulatory guidance.

C.1.3.1.3.1 Reactor Vessel Materials Surveillance Program

This evaluation should 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 because of the proposed plant change. If a schedule change is required, the applicant should demonstrate that the RVMSP is acceptable to demonstrate the integrity of the RPV through the end of the licensing period.

C.1.3.1.3.2 Pressure-Temperature Limits and Upper-Shelf Energy

The evaluation of the effect of the plant change on PTLs should do the following:

- Describe the PTL methodology.
- Provide the calculations for the number of EFPYs during the licensing period and indicate

whether the plant change would affect the EFPY calculation.

- Assess the effects of neutron embrittlement on the RPV material properties.
- Assess the effects of thermal embrittlement for susceptible materials.

C.1.3.1.3.3 Reactor Coolant Pressure Boundary Materials

The RCPBMs are those materials used to fabricate the systems and components that contain the high-pressure fluids produced in the reactor. This evaluation addresses the effects of the proposed plant changes on these materials and components. Specifically, an evaluation should do the following:

- Identify changes in, or related to, the material specifications.
- Assess compatibility with the reactor coolant.
- Identify applicable fabrication and processing methods and standards.
- Describe known susceptibilities to degradation.
- Identify AMPs associated with RCPBMs.

C.1.3.1.3.4 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. The PTS evaluation provides assurance that the RPV has adequate fracture toughness. The applicant should consider the effect of plant changes on the fracture toughness of the plant's limiting material, the loading transients associated with a PTS event, and the risk of failure resulting from a PTS scenario. This evaluation should demonstrate that the likelihood of RPV failure resulting from PTS remains acceptable as a result of the proposed plant changes. Specifically, this evaluation should do the following:

- Describe the PTS methodology.
- Provide the calculations for the original (i.e., before the plant change) PTS reference temperature (RT_{PTS}) at the expiration of the license.

The evaluation should also assess the effect of the proposed plant changes on the following:

- the loading transients that occur during a PTS event,
- the fracture toughness of applicable beltline materials as altered by neutron or thermal embrittlement or both, and
- the likelihood of initiation and growth of preexisting flaws.

If the fracture toughness of the limiting materials is affected, the applicant should calculate an updated RT_{PTS} and evaluate the significance of differences compared to the original RT_{PTS}.

C.1.3.1.3.5 Leak before Break

The LBB analyses provide a means for addressing the requirements for protecting against the dynamic effects of postulated pipe ruptures. If LBB approval has been granted within the PLP, the applicant should evaluate the effects of proposed plant changes on the LBB analysis. This analysis should identify and evaluate differences between the updated and existing LBB analysis of record and should specifically address the following:

- direct pipe failure mechanisms, and

- indirect pipe failure mechanisms.

C.1.3.1.3.6 Chemical and Volume Control System

The CVCS and boron recovery system provide a means for regulating the primary system water chemistry under both normal and accident conditions in PWR plant. For PWR plants, the applicant should do the following:

- Evaluate the effect of proposed plant changes on the primary system water chemistry.
- Demonstrate that adequate corrosion control is maintained within the PLP and PBSCs.

C.1.3.1.3.7 Reactor Water Cleanup System

The RWCS provides a means for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant in BWR plants. The applicant should do the following:

- Evaluate the effect of proposed plant changes on the primary system water chemistry as regulated by the RWCS.
- Demonstrate that adequate corrosion control is maintained within the PLP and PBSCs.

C.1.3.1.3.8 Pressure-Retaining Components and Component Supports

The structural integrity of the PRC/CS is designed in accordance with ASME Code, Section III, Division 1. The applicant's evaluation of the effect of proposed plant changes on the PRC/CS should do the following:

- Consider the 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.
- Address flow-induced vibration and compare the resulting stresses and cumulative fatigue usage factors with ASME Code allowable limits.
- 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 and demonstrate that these differences are insignificant and that the required ASME Code margins are retained.

C.1.3.2 Plant Changes That May Affect Indirect Failure Frequencies

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. 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 (Figure 2). This regulatory guide provides two acceptable options for this analysis. Option I uses the results of prior indirect failure analyses that show compliance with existing regulations. Under this option, the applicant should evaluate the relevance and sufficiency of prior analyses to ensure that they adequately address impacts resulting from the proposed plant changes (Figure 2). If the prior analyses are not sufficient, the applicant should supplement them with additional evaluation. Alternatively, Option II requires the applicant to evaluate the impact of the proposed plant changes without relying on prior indirect failure analyses. The applicant may choose either option to evaluate the impact of plant changes on dynamic effects (Section C.1.3.2.1) and missile protection (Section C.1.3.2.2).

C.1.3.2.1 *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 applicant should assess the effect of proposed design, operational, or maintenance changes within the primary and nonprimary pressure boundary systems on the following:

- the design adequacy of the PLP and PBSC system, and
- the PLP and PBSC supports.

Specifically, the applicant should determine the rupture locations and dynamic effects (Figure 2). The applicant should then evaluate the effects of the plant changes on the intended PLP and PBSC design functions (Figure 2) 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 the following:

- the criteria for defining pipe break and crack locations and configurations,
- 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
- pipe whip dynamic analyses, effects, and results, including the consideration of jet thrust and impingement forcing functions.

C.1.3.2.2 *Impact of Plant Changes on Missile Protection*

The applicant should evaluate the effect of plant changes on possible PLP and PBSC failures caused by missiles (Figure 2). The applicant's evaluation should do the following:

- Identify potential missile sources among applicable pressurized components and systems and high-speed rotating machinery.
- Identify additional missile sources (i.e., sources not identified in existing approved analysis) resulting from the proposed plant changes.
- Determine the likelihood of these missiles.
- Evaluate the missile protection of the PLP and PBSCs.

C.2 NUREG-1903 Applicability

C.2.1 General Considerations

NUREG-1903 assessed the likelihood that rare seismic events induce primary system failures larger than the postulated TBS. In particular, the study evaluated direct failures of the PLP to determine critical flaw sizes. The plant-specific risk of direct PLP and PBSC failures is acceptably smaller than the risk associated with generic, passive system, nonseismic LOCAs if the systems contain flaws smaller than these critical sizes. For the cases studied in NUREG-1903, large circumferential flaws fail under rare seismic events when the flaw depth is a significant percentage of the wall thickness. However, because the NUREG-1903 analysis was not intended to be bounding, the actual critical flaw depth for a specific plant may be smaller than these estimates.

An applicant can use either of the two approaches described in the following sections to estimate the critical flaw size within the PLP for a rare seismic event.

C.2.1.1 Bounding Analysis

In this approach, the applicant should demonstrate the following:

- The plant-specific PLP stresses, materials, material properties (including any aging-related property changes), and site-specific hazard information individually fall within, or are bounded by, the ranges considered in NUREG-1903.
- The plant-specific combination of the PLP stresses, materials, material properties (including any aging-related property changes), and site-specific hazard information are bounded by evaluations currently contained in NUREG-1903.

C.2.1.2 Direct Analysis

An alternate approach calculates the plant-specific critical flaw sizes. The applicant may use this analysis 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. The applicant may also find it advantageous to use bounding values for certain variables to simplify this analysis.

Figure 3 depicts a process for determining whether the bounding analysis can be adopted or whether direct analysis is required.

C.2.1.2.1 Analysis Requirements

The applicant should initially determine the scope of the analysis (Figure 3). The evaluation of the analysis scope should do the following:

- Consider all piping systems having an inner diameter that is greater than the TBS.
- Identify the critical locations within the piping systems.
- Provide the basis for the selected critical locations.
- Verify that the critical locations are included within the plant's ISI program and receive periodic examination.

C.2.1.2.2 Component Stresses

The applicant should next determine the stresses at the critical locations. The subsequent analysis will use these stresses to determine the critical flaw sizes. The NRC staff considers any of the three options described in the following sections to be acceptable for determining the component stresses.

C.2.1.2.2.1 Option I: NUREG-1903 Results

Option I (Figure 3) allows the applicant to choose the stress values determined in NUREG-1903 for its plant as long as those values are applicable. To use this option, the applicant should demonstrate that the following three conditions are satisfied:

(1) The site-specific seismic hazard curve and UHS are either bounded or represented by the applicable seismic hazard curve and UHS (i.e., from Reference 33) as extended to a 10^{-6}/yr probability of exceedance in NUREG-1903. Part of this assessment should determine whether any new information (e.g., as contained in ANSI/ANS 58.21 (Ref. 34)) impacts the validity of the hazard estimates used in NUREG-1903.

(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. This evaluation should address the effects of material property uncertainty when identifying the critical PLP locations.

(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. Note that this option is only available to the specific plants analyzed in NUREG-1903.

C.2.1.2.2.2 Option II: NUREG-1903 Scale-Factor Method

Option II (Figure 3) uses the scale factor method described in NUREG-1903 to determine the component stresses. The applicant should first develop the seismic hazard information by doing the following:

- Determine the site-specific seismic hazard curve and UHS or justifying the use of existing hazard information (e.g., as in References 31 and 33) for the site out to a 10^{-6}/yr probability of exceedance.
- Assess whether any new information impacts the validity of the existing hazard estimates.
- Address uncertainties when developing the site-specific seismic hazard information.

Next, the applicant should do the following:

- Determine the axially oriented, normal operating and SSE stresses, as described for Service Level A and D loadings, respectively, in ASME Code, Sections III and XI.
- Extrapolate the SSE stresses to seismic stresses representative of a 10^{-6}/yr probability of exceedance by directly calculating the scale factor, as described in Section 4.5 of NUREG-1903 (Ref. 4), or by using the appropriate scale factor provided in Appendix A to this regulatory guide.

C.2.1.2.2.3 Option III: Direct Analysis

Option III (Figure 3) allows the applicant to determine the component stresses at the critical locations by direct analysis. For this analysis, the applicant should first determine the axially oriented, normal operating stresses at the limiting locations, as described for Service Level A loadings in ASME Code, Sections III and XI. Then the applicant should determine the seismically induced component stresses by doing the following:

- Develop an updated, representative site-specific hazard curve and ground motion UHS for a 10^{-6}/yr probability of exceedance.
- Model the site-specific foundation properties for the 10^{-6}/yr seismic hazard.
- Construct 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 the PLP.
- Perform an SSI analyses for the given seismic input motion, soil/rock model, and structural models.
- Address modeling and input uncertainties and their effects on the PLP stresses at the critical locations.

C.2.1.2.3 Material Properties

If the applicant demonstrates that the material properties in the NUREG-1903 analysis either represent or conservatively bound the plant-specific properties at the limiting locations, the plant-specific critical flaw sizes may be determined directly from the NUREG-1903 results. One acceptable approach would be to demonstrate that either the material toughness properties allowed by the ASME Code, or the actual material properties, are equivalent or greater than the properties utilized in the NUREG-1903 analysis. Additionally, the associated tensile properties should be equivalent or less than the properties utilized in the NUREG-1903 analysis. To make this comparison, the applicant should do the following:

- Determine the material properties at the operating temperature at each limiting location.
- Account for any age-related degradation of the strength and toughness properties.
- Consider effects on these material properties caused by the elevated loading rates associated with a seismic event.
- Assess the effects of uncertainty and variability in material properties.

If ASME Code properties are used for this comparison, the applicant should demonstrate that they conservatively represent the limiting material properties after addressing the preceding effects

If the applicant cannot demonstrate that the material properties used in the NUREG-1903 analysis are applicable, the applicant should develop representative or conservative plant-specific material properties to use in a plant-specific critical flaw size analysis (Figure 3). As in the analysis above, this evaluation should do the following:

- Determine the tensile and fracture toughness properties at the operating temperature at each limiting location.
- Account for age-related degradation of the strength and toughness properties.
- Consider the effects on these material properties caused by the elevated loading rates associated with a seismic event.
- Assess the effects of uncertainty and variability in material properties.

If ASME Code properties are used for this evaluation, the applicant should demonstrate that they conservatively represent the limiting material properties after addressing the preceding effects

C.2.1.2.4 NUREG-1903 Critical Surface Flaw Analysis

The NRC staff considers either of the two options described in the following sections to be acceptable for determining the critical surface flaw sizes consistent with the approach used in NUREG-1903.

C.2.1.2.4.1 Option I: NUREG-1903 Critical Flaw Sizes

If the material properties used in NUREG-1903 are applicable to the plant-specific materials (as demonstrated in Section C.2.1.2.3), the applicant may be able to determine plant-specific critical flaw sizes directly from the NUREG-1903 results. To directly use the NUREG-1903 results, the applicant must also demonstrate that the normal operating plus 10^{-6}/yr seismic stresses are less than the upper bound (UB) stresses evaluated in NUREG-1903 at each critical location (Figure 3). An acceptable demonstration would do the following:

- Combine the axially oriented, normal operating stress and the 10^{-6}/yr seismic stresses determined in Section C.2.1.2.2 to calculate the total stress associated with a 10^{-6}/yr seismic event.

- Determine whether the total stress is less than the 35-ksi UB evaluated in NUREG-1903.

For total stress values between 10 and 35 ksi, the analysis should determine the ratio of critical flaw depth to component thickness for a surface flaw having a length of $\theta/\pi = 0.8$ in austenitic pipe using

the NUREG-1903 results. 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.

C.2.1.2.4.2 Option II: Plant-Specific Analysis

If the total stress calculated in Section C.2.1.2.4.1 is greater than 35 ksi or if the plant-specific material properties are such that the Section C.2.1.2.4.1 is not applicable, a plant-specific analysis will be needed to determine the critical flaw depth (Figure 3). In this analysis, the critical flaw size at each limiting location is determined using the component stresses and material properties determined in Sections C.2.1.2.2 and C.2.1.2.3, respectively (Figure 3). The principal steps in the analysis should do the following:

- Combine the normal operating and 10^{-6}/yr seismic stresses from Section C.2.1.2.2 to determine the total stress associated with a 10^{-6}/yr seismic event.
- Apply the NUREG-1903 plasticity correction factor, if appropriate, to account for plasticity within the component under seismic loading.
- Determine the NUREG-1903 Z-factor correction for the limiting material, or materials,
- Use this Z-factor with the limit-load solution to determine the critical flaw depth using the direct analytical methods presented in ASME Code, Section XI, Appendix C for elastic-plastic failure (Article IWB-3640). The analysis sets the ASME Code structural factor to 1.0.
- In this analysis, the assumed flaw length should be $\theta/\pi = 0.8$, and the flaw should be oriented circumferentially in the worst possible location relative to the bending plane.

Alternatively, the applicant can also determine the critical flaw size using EPFM predictions of component failure without applying the Z-factor approach. In this analysis, the applicant should use the applied stresses determined in Section C.2.1.2.2 and the material properties determined in Section C.2.1.2.3. NUREG/CR-6298 (Ref. 42) provides additional detail on directly calculating component failure using EPFM.

C.2.1.2.5 <u>ASME Code, Section XI, Critical Surface Flaw Analysis</u>

If the critical flaw depths calculated for each limiting location in Section C.2.1.2.4 are not at least 25 percent of the through-wall thickness of the pipe, the applicant should compare the depths to existing flaws allowed under the ASME Code (Figure 3) for the normal operating plus SSE design stresses. Articles 3500 or 3600 apply to elastic-plastic failure of circumferential flaws, and the applicant should use these articles with all of their associated requirements. Additionally, the applicant can choose either representative or ASME Code material properties, as allowable under Section XI of the ASME Code.

The applicant should then use the ASME Code stresses and selected material properties 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 C.2.1.2.4.2 the flaw at each limiting location should be oriented circumferentially in the position around the pipe circumference with respect to the global bending plane to obtain the maximum axial total stress. The applicant should compare the critical flaw depths determined in this analysis to the flaw depths determined in Section C.2.1.2.4.2 to assess the seismic frequency contributions associated with these flaws using the acceptance criteria in Section C.2.1.2.6.

C.2.1.2.6 Seismic Frequency Contributions

The final step in the analysis is to determine whether the frequency associated with the direct, seismically induced failure of the PLP is significantly less than the failure frequency caused by the loading histories and component degradations considered in NUREG-1829 (Figure 3). If any of the following three criteria are satisfied at each analyzed location, the seismic risk of direct PLP failure is considered to be acceptably low:

(1) The critical flaw depths calculated in Section C.2.1.2.4 are greater than 25 percent of the thickness.
(2) The critical flaw depths calculated in Section C.2.1.2.4.2 are greater than the ASME Code, Section XI, flaw acceptance criteria calculated in Section C.2.1.2.5.
(3) The ISI programs are sufficient for detecting flaws before reaching the critical flaw depths calculated in Section C.2.1.2.4.2 of this regulatory guide.

The first criterion (Figure 3) is satisfied at each limiting location if the critical depth for a surface flaw with a length of $\theta/\pi = 0.8$, as determined in Section C.2.1.2.4 of this report, is greater than 25 percent of the PLP thickness. Additionally, the applicant should confirm that the ISI programs inspect these locations and that the programs satisfy either ASME Code, Section XI (including Appendix VIII), or other applicable NRC-approved requirements. If these locations are not currently inspected, existing ISI programs should be augmented to include inspection at each limiting location.

The second criterion (Figure 3) is satisfied if the more realistic, critical flaw depth calculated in Section C.2.1.2.4.2 (i.e., using the NUREG-1903 approach) is larger than the depth calculated in Section C.2.1.2.5 (i.e., using ASME Code, Section XI, for N+SSE design loads and ASME Code structural factors). If this criterion is satisfied, the applicant should confirm that ISI programs inspect these locations and that the programs satisfy either ASME Code, Section XI (including Appendix VIII), or other applicable NRC-approved requirements that are more conservative than the ASME Code requirements. If these locations are not currently inspected, existing ISI programs should be augmented to include inspection at each limiting location.

The third criterion (Figure 3) requires the applicant to demonstrate that current or planned inspections can reliably and accurately detect flaws at each limiting location such that these flaws will be repaired before they reach the critical flaw depths calculated in Section C.2.1.2.4.2. At each limiting location, the applicant should do the following:

- Confirm that the location is inspected under existing ISI programs or augment these programs to ensure inspection at these locations.
- Establish surface and embedded flaw detectability limits for a variety of flaw depths and aspect (i.e., length-to-depth) ratios that are less than the critical flaw sizes calculated in Section C.2.1.2.4.2.
- Describe the applicable ISI programs and quality assurance provisions.
- Demonstrate that the ISI programs are consistent with the requirements of ASME Code, Section XI, Appendix VIII or other applicable NRC-approved requirements that are more conservative than the ASME Code requirements.
- Demonstrate that the ISI programs provide reasonable assurance that flaws sizes equivalent to the detectability limits can be reliably detected in practice.

- Demonstrate that the inspection periodicity is sufficient to ensure that flaws will not exceed the critical flaw depths calculated in Section C.2.1.2.4.2 between planned inspections.

C.2.1.3 Stress-Corrosion Cracking Mitigation

The final step in the NUREG-1903 applicability analysis (Figure 3) requires the applicant to demonstrate that there is an insignificant failure frequency at SCC-mitigated locations in BWRs and PWRs associated with rare (i.e., 10^{-6}/yr) seismic events. One acceptable approach is to demonstrate that the mitigation has been designed and implemented such that the minimum structural factor required by ASME Code, Section III, is maintained for Service Level C/D, or SSE, loading. Using this approach, the applicant should consider the effects of the maximum-allowable, premitigation flaw when determining the SSE structural factor, and confirm, as in Section C.1.1.1.2 of this guide, 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 approved inspection procedures.

Specifically, the applicant should confirm that the ISI plan is sufficient such that the following is true:

- Premitigation inspection can reliably and accurately detect flaws that are equivalent to or less than the maximum flaw depth allowed for that mitigation technique.
- Postmitigation inspections can reliably and accurately detect both the growth of preexisting flaws identified in the premitigation inspection and flaws that exceed the maximum flaw depth allowed for the specific mitigation technique.
- 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.

If credit for residual stress redistribution is necessary to satisfy the minimum SSE structural factor in the ASME Code, the applicant should conduct a complete nonlinear flaw instability analysis to simulate the development of the residual stress by the mitigation technique and the addition of the 10^{-6}/yr seismic stresses for the maximum allowable flaw depth (see Section B.2.1.3). This analysis is necessary to demonstrate that the stress redistribution is still effective and provides acceptable margin for the 10^{-6}/yr seismic event at the mitigation locations.

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

D. IMPLEMENTATION

The purpose of this section is to provide information to applicants and licensees regarding the NRC's plans for using this draft regulatory guide. The NRC does not intend or approve any imposition or backfit in connection with its issuance.

The NRC has issued this draft guide to encourage public participation in its development. The NRC will consider all public comments received in development of the final guidance document. In some cases, applicants or licensees may propose an alternative or use a previously established acceptable alternative method for complying with specified portions of the NRC's regulations. Otherwise, the methods described in this guide will be used in evaluating compliance with the applicable regulations for license applications, license amendment applications, and amendment requests.

ABBREVIATIONS AND ACRONYMS

AMP	aging management program
ANS	American National Standard
ANSI	American National Standards Institute
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
cm/s^2	centimeter per square second
CVCS	chemical and volume control system
DMW	dissimilar metal weld
ECCS	emergency core cooling system
EFPY	effective full-power year
EPFM	electric-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
LB	licensing basis
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
NEI	Nuclear Energy Institute

NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OD	outside diameter
OMB	Office of Management and Budget
PBSC	pressure boundary structural component
PGA	peak ground acceleration
PIFRAC	piping fracture database
PLP	primary 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
psi	pounds per square inch
psig	pounds per square inch gauge
PTL	pressure-temperature limit
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
RCPB	reactor coolant pressure boundary
RCPBM	reactor coolant pressure boundary material
RPV	reactor pressure vessel
RS	review standard
RT_{PTS}	pressurized thermal shock reference temperature
RVMSP	reactor vessel materials surveillance program
RWCS	reactor water cleanup system
S_{EC}	elastic plastic fracture mechanics-corrected stress
S_{El}	normal plus 10^{-6}/yr seismic stress
S_m	ASME design stress intensity allowable, Class 1 components
S_{NL}	nonlinear stress
S_Y	material yield strength
S_u	material ultimate strength
SAW	submerged arc weld
SCC	stress-corrosion cracking
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
USE	upper-shelf energy
UHS	uniform hazard spectra
W	Westinghouse
yr	year
Z-factor	ratio of the failure stress predicted from a limit-load calculation to the failure stress predicted using elastic-plastic fracture mechanics

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[1] All NRC regulations listed herein are available electronically through the Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/cfr/. Copies are also available for inspection or copying for a fee from the NRC's Public Document Room (PDR) at 11555 Rockville Pike, Rockville, MD; the mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; and e-mail pdr.resource@nrc.gov.

[2] All NUREG-series reports listed herein were published by the U.S. Nuclear Regulatory Commission. Most are available electronically through the Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/nuregs/. Copies are also available for inspection or copying for a fee from the NRC's Public Document Room (PDR) at 11555 Rockville Pike, Rockville, MD; the mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; and e-mail pdr.resource@nrc.gov.

[3] All Commission papers (SECYs) listed herein were published by the U.S. Nuclear Regulatory Commission. Commission papers are available electronically through the Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/commission/secys/. Copies are also available for inspection or copying for a fee from the NRC's Public Document Room (PDR) at 11555 Rockville Pike, Rockville, MD; the mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; and e-mail pdr.resource@nrc.gov.

[4] Copies of American Society for Testing and Materials (ASTM) standards may be purchased from ASTM, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, Pennsylvania 19428-2959; telephone (610) 832-9585. Purchase information is available through the ASTM Web site at http://www.astm.org.

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[6] Generic Letters (GLs) listed herein are available electronically through the Public Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/gen-comm/gen-letters/
Copies are also available for inspection or copying for a fee from the NRC's Public Document Room at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; e-mail pdr.resource@nrc.gov.

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[8] All regulatory guides listed herein were published by the U.S. Nuclear Regulatory Commission. Where an ADAMS accession number is identified, the specified regulatory guide is available electronically through the NRC's Agencywide Documents Access and Management System (ADAMS) at http://www.nrc.gov/reading-rm/adams.html. All other regulatory guides are available electronically through the Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/reg-guides/.

[9] All regulatory guides listed herein were published by the U.S. Nuclear Regulatory Commission. Where an ADAMS accession number is identified, the specified regulatory guide is available electronically through the NRC's Agencywide Documents Access and Management System (ADAMS) at http://www.nrc.gov/reading-rm/adams.html. All other regulatory guides are available electronically through the Electronic Reading Room on the NRC's public Web site, at http://www.nrc.gov/reading-rm/doc-collections/reg-guides/.

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APPENDIX A

DETAILED INFORMATION FOR CONDUCTING PLANT-SPECIFIC ANALYSES USING NUREG-1903 APPROACH

This appendix contains information used in performing the seismic analyses in NUREG-1903, "Seismic Considerations for the Transition Break Size," issued February 2008. The plant names are coded, and the codes have been changed for each unique table. Licensees can contact the U.S. Nuclear Regulatory Commission 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 safe-shutdown earthquake (SSE) peak ground acceleration (PGA) values, Weibull fit coefficients to mean PGA probability curves, and calculated PGA values at seismic event with a frequency of 10^{-6} per year (yr)

Table A-3 Pressurized-water reactor (PWR) coolant piping information and calculated values by plant, such as the following:

- plant code number
- segment of primary pipe loop used in evaluation (e.g., hot leg, cold leg)
- pipe dimensions
- materials at hypothetical crack location (base metal and weld metals)
- yield, ultimate, and flow stress using the American Society of Mechanical Engineers (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 of the following:
    - ASME Code, Section XI, values
    - updated values from BE elastic-plastic fracture mechanics analyses to account for dynamic and cyclic corrections
- normal operating temperature, pressure, and deadweight and thermal expansion stresses
- design SSE stresses
- calculated elastic stresses for a 10^{-6}/yr seismic event (linearly scaled from seismic hazard curves)
- scaling factor on original seismic design (accounts for conservatisms in original seismic analyses compared to current state-of-the-art seismic analyses)
- calculated elastic stresses for a 10^{-6}/yr seismic event with scaling factor correction
- 10^{-6}/yr stresses with additional nonlinear stress correction factor
- calculated surface-crack depths as a function of crack length at normal operating stress (N)+10^{-6}/yr corrected seismic stress using the following:
    - ASME Code analysis with code strengths
    - ASME Code analysis with typical actual strengths
    - 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 10^{-6}/yr Seismic Event

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 the 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 centimeters per square second (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 10^{-6}/yr Seismic Event (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 the 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 10^{-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 10^{-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 with seismic scale factor, ksi	N+10E-6 stress with seismic scale factor and 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 Best Estimate 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 Best Estimate 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

EXAMPLE CALCULATION FOR HOT LEG (CRITICAL LOCATION IS THE GIRTH WELD OF AN SA312-TP304N SEAMLESS PIPE TO THE REACTOR PRESSURE VESSEL NOZZLE)

Steps in the Seismic Consideration Analysis

1. Obtain seismic hazard curve coefficients.

The 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). From Table A-2, for site code “U,” the safe-shutdown earthquake (SSE) probability column provides P(x) = 5.34×10^{-5}.

2. Solve for PGA value at 1×10^{-6} per year (yr) probability of occurrence. Results are identical to Example 1 results as follows:

    a. Solving gives $\chi = 0.876$ g.
    b. Ratio of PGA for 1×10^{-6}/yr to SSE = 4.380.

3. Determine the highest SSE stress location (values correspond to “Plant v” in Tables A-3a, b, and c for hot leg).

    a. This information can be obtained from past leak-before-break (LBB) submittals or other plant design information.

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

    a. There is a shielded metal arc weld/submerged arc weld (SMAW/SAW) joining the piping to a safe-end at the reactor pressure vessel (RPV) nozzle.
    b. The base metal of the pipe is TP304N wrought austenitic stainless steel, and there is a safe-end of TP304N stainless steel on the other side of the critical weld. The safe-end is short and there is a dissimilar metal weld (DMW) between the safe-end and the RPV nozzle. The DMW toughness is much greater than the stainless steel weld metal toughness. The stainless steel SAW weld toughness and the TP304N strength were used since they were lower bounding in this case.

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

    a. For the hot leg of “Plant v” in Table A-3a, the inside diameter of the pipe is 29 inches and the pipe thickness is 2.45 inches.
    b. The outside diameter is calculated to be 33.9 inches.

6. Determine normal operating conditions and stresses (values correspond to “Plant v” in Table A-3b).

a. Normal operating pressures and temperatures are 2,250 pounds per square inch gauge and 617 degrees Fahrenheit (F), respectively.
b. The maximum normal operating stress (N), including the pressure stress, deadweight, and thermal expansion stress, is 16.15 kilopounds per square inch (ksi).

7. Determine strength values for materials of interest.

a. Using material properties identified in the American Society of Mechanical Engineers (ASME) Code, the following is obtained:
   i. For SA312 TP304N wrought stainless steel at 617 degrees F, the material yield strength (S_y) value is 19.76 ksi (interpolated between the values of 600 degrees F and 650 degrees F in Table Y-1, page 653, line 19, of Section II, Part D, of the ASME Boiler and Pressure Vessel Code, 2007 Edition).
   ii. For SA312 TP304N wrought stainless steel at 617 degrees F, the material tensile strength (S_u) value is 69.5 ksi (interpolated between the values of 600 degrees F and 650 degrees F in Table U, page 523, line 34, of Section II, Part D, of the 2007 ASME Code).
   iii. The flow stress (average of yield and ultimate strengths) is equal to 44.63 ksi.
   iv. S_m at 617 degrees F is 17.76 ksi (interpolated between the values of 600 degrees F and 650 degrees F in Table 2A, page 322, line 24, of Section II, Part D, of the 2007 ASME Code).

b. Using typical average material properties (values obtained from PIFRAC Database[1]), the following is obtained:

[1] The average values of yield and ultimate strength at 550 degrees F can be found in NUREG/CR-6004; the value of 650 degrees F was derived from the PIFRAC database.

i. For SA312 TP304N wrought stainless steel at 617 degrees F, the S_y value is 20.78 ksi.
ii. For SA312 TP304N wrought stainless steel at 617 degrees F, the S_u value is 63.47 ksi.
iii. The flow stress (average of yield and ultimate strengths) is equal to 42.12 ksi.
iv. The calculated S_m value (based on 90 percent of yield at temperature) is 18.71 ksi.

8. Determine the SSE stresses (value corresponds to “Plant v” in Table A-3b).

   a. The SSE design stress in the hot-leg pipe at this location is 12.96 ksi. This is the unintensified stress for a pipe butt weld.

9. Determine the linearly scaled seismic stress for the 10^{-6}/yr seismic event.
   a. The value is the SSE stress multiplied by the ratio of PGA at 1×10^{-6}/yr to PGA at SSE from Step 3. (This value is also listed in Table A-3b for the hot leg of “Plant v”).
   b. This stress is 4.38 * 12.96 ksi = 56.77 ksi.

10. Apply seismic scaling factor for plant site to correct the linearly scaled stresses from Step 9 and add the normal operating stresses for the 10^{-6}/yr seismic event.

   a. The seismic scaling factors for the different plant sites account for conservatisms in the original seismic design analysis to obtain a best estimate (BE) value. This value is equivalent to the reciprocal of the safety factor in the original design.
   b. The seismic scaling factor is 0.528 for this case (value corresponds to “Plant v” in Table A-3b).
   c. The correction to the linearly scaled stresses (from Step 9) is 0.528 * 56.77 ksi = 30.0 ksi.
   d. The normal plus 10^{-6}/yr seismic stress (S_{El}) is 30.0 + 16.15 ksi = 46.15 ksi.

11. Apply a nonlinear correction factor to the elastic normal plus 10^{-6}/yr seismic stresses from Step 10 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 elastic stress versus nonlinear stress curve is bilinear, as illustrated in Figure B-1a below, when using ASME Code strength properties, or Figure B-1b when using typical average properties.
   c. If S_{El} (from Step 10) is below the yield strength then the correction factor = 1.0 and

   $$S_{NL} = S_{El} \qquad \text{(B2.1a)}$$

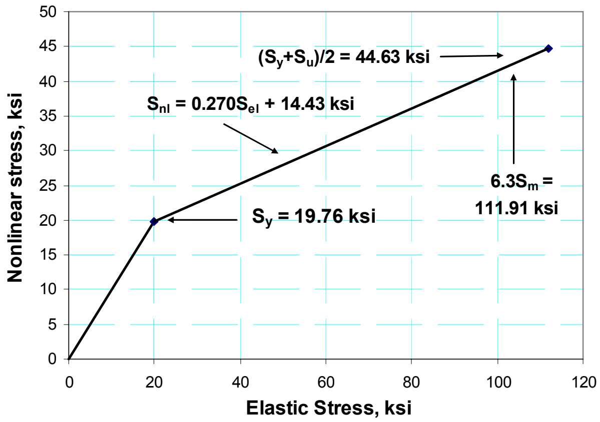
   d. If $S_{El} > S_Y$ then, from Figure B-1a for TP304N, S_{NL} using the ASME Code strength values is

   $$\text{ASME Code Values: } S_{NL} = 0.270*(S_{El}) + 14.43 \qquad \text{(B2.1b)}$$

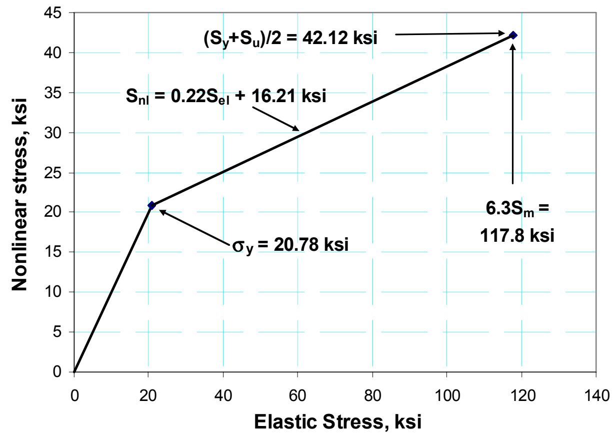
Using typical average properties from Figure B-1b for TP304N gives

$$\text{Typical average values: } S_{NL} = 0.220*(S_{El}) + 16.2 \qquad \text{(B2.1c)}$$

e. In this example, S_{El} = 46.15 ksi, S_{NL} (from Equation B2.1b) = 26.88 ksi for ASME Code values of strength and 26.33 ksi for typical average values of strength.



(a) Using ASME Code strength and S_m values



(b) Using typical average strength and calculated S_m values

Figure B-1. Elastic-stress correction curves for TP304N using ASME Code and typical average strength values at 617 degrees F

12. Determine the elastic-plastic correction factor (Z-factor) for the critical flaw size evaluation. In NUREG-1903, the Z-factors were derived using relationships that more accurately (and less conservatively) predict full-scale pipe test failure. In this example, the following applies:

   a. 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. (Seismic loading increases the toughness of a stainless steel SAW.) A simple linear J-RM curve was used with $J = 1.047 + 4.333\Delta a$ (in-lb/in^2 with Δa in inches).
   b. The Z-factor was derived for pressurized-water reactor primary piping with R/t of 5 to 5.5.
   c. The outside diameter (OD) of the cold-leg pipe (value corresponds to "Plant v" in Table A-3a) is 33.9 inches and was used for developing Equation B2.2 rather than nominal pipe size (NPS).
   d. The Z-factor for this SMAW pipe case is given by Equation B.3 below and is 1.639. The hot-leg pipe is TP304N, but the toughness location of interest is in the SMAW weld. These Z-factors can also be obtained from Figure 4-9 in NUREG-1903 for SMAW.

$$Z = 1.0922 + 0.15025D - 0.0185D^2 + 0.0011889D^3 - 0.00004102D^4 + 0.00000071875D^5 - 0.000000005014D^6 \qquad \text{(B2.2)}$$

Where,
D = pipe outside diameter, inch

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

   a. The EPFM-corrected stress is the Z-factor (from Step 12) multiplied by nonlinear stress (from Step 11).
   b. In this example, the S_{EC} = 1.639 * 26.88 ksi = 44.06 ksi using the S_{NL} for the ASME Code strength properties, or 1.639 * 26.36 ksi = 43.21 ksi using the S_{NL} for the typical average strength values.

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

   a. ASME Code, Section XI, Appendix C, provides the limit-load equations, which are replicated in Equations B2.3a–B2.3c below for convenience. Note that in this calculation, the structural factor 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, Section XI, Appendix C) are:

$$\sigma_b^c = (2\sigma_f/\pi)(2-a/t)\sin(\beta) \qquad \text{(B2.3a)}$$

$$\beta = \pi/(2-a/t)(1-a/t-\sigma_m/\sigma_f) \qquad \text{(B2.3b)}$$

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 B2.3a and B2.3b can be rearranged to give:

$$a/t = 2 - [(\pi/2)(\sigma_b^c/\sigma_f)]/\sin[\pi/(2-a/t)(1-a/t-\sigma_m/\sigma_f)] \quad \text{(B2.3c)}$$

The above equation is solved iteratively for the a/t value.

d. In this example,
σ_m= 7.783 ksi (from pressure stress, using PD/4t with D = OD per ASME Code equations)
σ_f= 44.63 ksi (using ASME Code properties from Step 8.a.3) or 42.12 ksi (using typical average properties from Step 8.b.4)
σ_m/σ_f= 0.174 (using ASME Code properties) or 0.185 (using typical average properties)
σ_b^c = 44.06 ksi (S_{EC} from Step 13 for ASME Code properties) minus 7.783 ksi (σ_m from above) = 36.28 ksi, or 43.21 ksi (S_{EC} from Step 13 for typical average properties) minus 7.783 ksi (σ_m from above) = 35.42 ksi
σ_b^c/σ_f= 0.816 (using ASME Code properties) or 0.843 (using typical average properties)

e. Solving Equation B2.3c iteratively with the above σ_b^c/σ_f and σ_m/σ_f values gives a/t values of 0.360 using ASME Code properties and 0.330 using typical average properties.

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

a. Determine the original plant N+SSE stresses for hot-leg location (values correspond to "Plant v" in Table A-3b).
   i. SSE stress = 12.96 ksi
   ii. N stress = 16.15 ksi for the normal operating stress
   iii. The total N+SSE = 29.11 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 = 17.063 ksi
   iii. σ_e = 7.02 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:

$$S_c = (1/SF_b)[\sigma_b^c/Z - \sigma_e] - \sigma_m [1 - 1/(Z\,SF_m)] \quad \text{(B2.4a)}$$

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 = NPS in inches. For primary piping, use the OD for the NPS.

   ii. Solving Equation B2.4a for σ_b^c yields the following:

$$\sigma_b^c = Z\{ SF_b [S_c + \sigma_m(1 - 1/(Z\,SF_m)) + \sigma_e]\} \quad \text{(B2.4b)}$$

   iii. In this example,
$S_c = \sigma_b$ = 17.063 ksi (from Step 15.b.ii)

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)
Note: Safety factors from Article C-2681 for Service Level D
σ_e = 7.02 ksi (from Step 15.b.iii)
σ_m = 7.783 ksi (from Step 15.b.i)
NPS = 33.9 inches (value corresponds to "Plant v" in Table A-3a). Note the OD used for the NPS for this nonstandard size since, for larger diameter pipes, the NPS is equal to the pipe OD.
Z = 1.30[1 + 0.010(NPS - 4)] = 1.689 (from Article C-6330 of 2007 ASME Code, Section XI, Appendix C using the pipe actual OD of 33.9 inches)
σ_b^c = 67.16 ksi (from Equation B2.4b)

d. Iteratively solve for the a/t value using Equation B2.3c from Step 14.c.
   i. In this example, using both the ASME Code and typical average strength values, a/t is less than 10 percent of the pipe thickness, so the flaw acceptance standards in Table IWB-3514-2 have to be used.

16. Evaluate the 10^{-6}/yr seismic a/t value from Step 14.e to the ASME Code a/t value from Step 15.d.

a. If the N + 10^{-6}/yr seismic a/t value is greater than 0.25 a/t, then the seismic frequency contribution is acceptable and the piping system passes the seismic assessment.
b. If the ASME Code a/t value is less than the N + 10^{-6}/yr seismic a/t value, then the seismic frequency contribution is acceptable and the piping system passes the seismic assessment.
c. If the ASME Code a/t value is greater than the N + 10^{-6}/yr seismic a/t value, then the applicant should demonstrate that the current inservice inspection programs can reliably and accurately detect flaws at each limiting location such that these flaws will be repaired before they reach the critical flaw depths calculated for N + 10^{-6}/yr seismic a/t value, as described in Section C.2.1.2.6 of the regulatory guide.

In this example, the ASME Code a/t value for the IWB-3514-2 tables is less than the BE 1×10^{-6}/yr seismic a/t value and greater than 0.25. Consequently, this example passes the transition break size requirements.